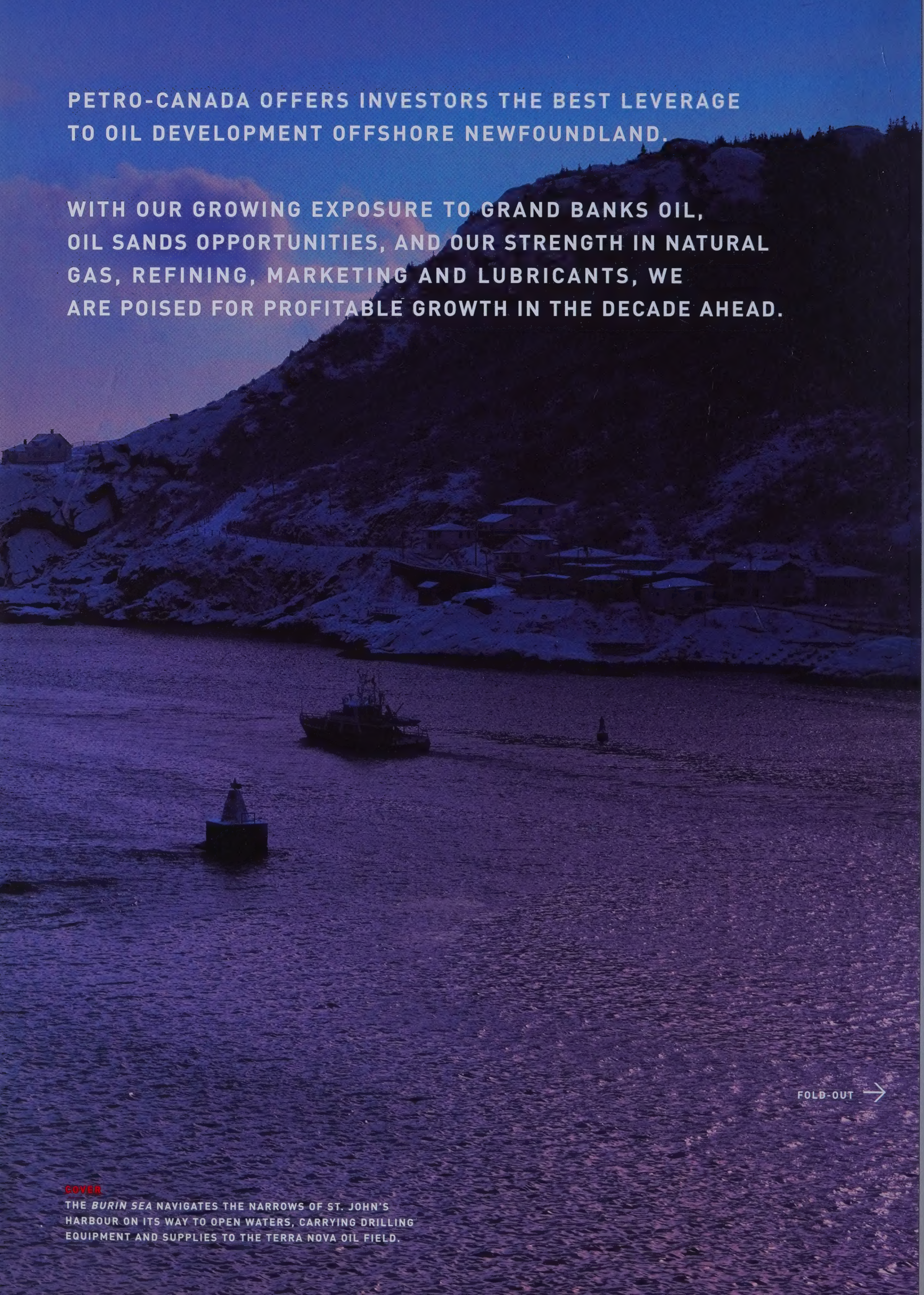
1999 ANNUAL REPORT

PETRO-CANADA

GRAND BANKS OIL: OUR CORNERSTONE FOR GROWTH

PETRO-CANADA OFFERS INVESTORS THE BEST LEVERAGE TO OIL DEVELOPMENT OFFSHORE NEWFOUNDLAND.

WITH OUR GROWING EXPOSURE TO GRAND BANKS OIL, OIL SANDS OPPORTUNITIES, AND OUR STRENGTH IN NATURAL GAS, REFINING, MARKETING AND LUBRICANTS, WE ARE POISED FOR PROFITABLE GROWTH IN THE DECADE AHEAD.



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COVER
THE *BURIN SEA* NAVIGATES THE NARROWS OF ST. JOHN'S HARBOUR ON ITS WAY TO OPEN WATERS, CARRYING DRILLING EQUIPMENT AND SUPPLIES TO THE TERRA NOVA OIL FIELD.

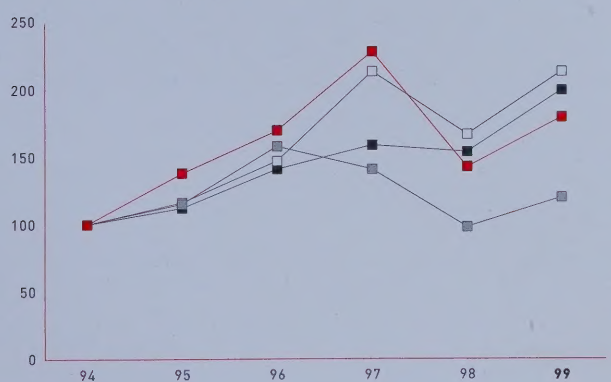
HIGHLIGHTS

(stated in millions of Canadian dollars, unless otherwise indicated)	**1999**	1998	1997
FINANCIAL			
Earnings from operations (in 1998, before reorganization costs)	**236**	130	314
Net earnings	**233**	95	306
Cash flow[1]	**964**	830	1 263
Per common share (dollars)			
Earnings from operations (in 1998, before reorganization costs)	**0.87**	0.48	1.16
Net earnings	**0.86**	0.35	1.13
Cash flow	**3.55**	3.06	4.66
Dividends	**0.34**	0.32	0.26
Expenditures on property, plant and equipment and exploration	**1 021**	1 116	1 049
Return on capital employed (per cent)	**5.6**	3.0	6.8
Cash flow return on capital employed (per cent)	**18.6**	16.3	24.5
Debt	**1 711**	1 829	1 741
Debt to debt plus equity (per cent)	**29.5**	31.7	30.7
Debt to cash flow (times)	**1.8**	2.2	1.4
Operating return on capital employed (per cent) (in 1998, before reorganization costs)	**5.6**	3.6	6.9
OPERATING			
Crude oil and field natural gas liquids production, net before royalties (thousands of barrels per day)	**95.3**	101.1	95.1
Natural gas production, net before royalties, excluding injectants (millions of cubic feet per day)	**719**	722	760
Proved oil and field natural gas liquids reserves, net before royalties (millions of barrels)	**476**	476	432
Proved natural gas reserves, net before royalties (trillions of cubic feet)	**2.5**	2.5	2.5
Refined petroleum product sales (thousands of cubic metres per day)	**51.2**	49.1	48.5
Refinery crude capacity utilization[2] (per cent)	**100**	95	103

1 Cash flow from operations before changes in non-cash working captital items.
2 Total daily rated refinery capacity was increased to 49.0 thousand cubic metres per day, from 45.4 thousand cubic metres per day, as a result of a reassessment in the fourth quarter of 1998.

FIVE-YEAR SHARE PRICE PERFORMANCE

During 1999, Petro-Canada shares appreciated 25.8 per cent.



(December 31, 1994 = 100)
Changes in yearly closing values for Petro-Canada common shares compared with the Toronto Stock Exchange 300 index, the Integrated Oils sub-index and the Oil & Gas Producers sub-index.

- Petro-Canada
- Toronto Stock Exchange 300 index
- Integrated Oils sub-index
- Oil & Gas Producers sub-index

CORE BUSINESSES AT A GLANCE

Petro-Canada is a major oil and gas company and a leader in the Canadian petroleum industry. Our portfolio of businesses spans both the upstream and downstream industry sectors.

Business Description

- Explores for, develops, produces and markets offshore oil
- 20% interest in the producing Hibernia field
- 29% interest in the Terra Nova oil development
- Owns major interests in other significant discoveries, including White Rose (17.5%) and Hebron/Ben Nevis (23.9%), as well as substantial exploration acreage

Strategy

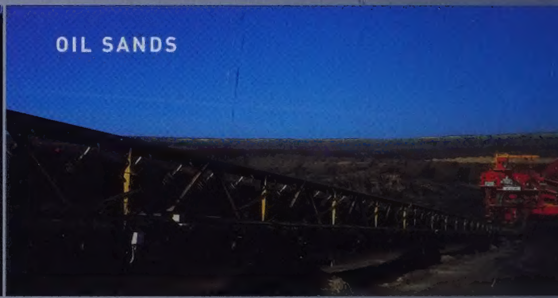
- Establish a light oil production base of at least 70 000 barrels per day by 2005 and sustain it through ongoing development of other fields

1999 Achievements

- Petro-Canada's Hibernia production averaged 20 000 barrels per day, (30 000 barrels per day in November and December)
- Revised Hibernia's ultimate reserves to 730 million barrels from 615 million barrels
- Subsea "glory holes" in the Terra Nova field completed, preparatory drilling begun, construction of vessel and topsides progressed
- Five delineation wells drilled — three at White Rose and two at Hebron/Ben Nevis
- Secured new exploration acreage in the Flemish Pass Basin

Plans for 2000

- Increase Petro-Canada's share of Hibernia production to 27 000 barrels per day
- Additional Hibernia drilling, including the first Avalon formation wells
- Advance Terra Nova toward first oil
- Drill at least four exploration or delineation wells
- Begin engineering and design for potential White Rose development



Business Description

- 12% interest in Syncrude — the world's largest oil sands development
- Owns working interests from 25% to 100% in several large *in situ* oil sands leases, including 100% working interest at MacKay River

Strategy

- Participate in the Syncrude mine and upgrading expansion, increasing our production to more than 50 000 barrels per day by 2007

1999 Achievements

- Petro-Canada's share of record Syncrude production reached 26 700 barrels per day
- Reduced Syncrude unit operating costs to $12.83 per barrel
- Continued drilling and evaluation of MacKay River oil sands leases

Plans for 2000

- Participate in the Syncrude expansion, increasing our share of production to 30 000 barrels per day
- Actively participate in development of northern Alberta's vast oil sands resources
- Continue evaluation of MacKay River oil sands leases and advance development plans

Business Description

- Explores for, produces and markets natural gas and associated liquids
- Among the largest producers in Western Canada, with 1999 daily sales of 719 million cubic feet of gas and 11 700 barrels of natural gas liquids

Strategy

- Profitably sustain the Western Canada gas business through focused exploration and development in our core areas — the Alberta Foothills, west-central Alberta and northeastern British Columbia

1999 Achievements

- Gas production rates held stable despite net sales and lower capital spending
- Added 277 billion cubic feet of proved gas reserves through the drill bit, replacing 106% of 1999 production
- Continued exploration and development success in the Alberta Foothills
- Continued disposition of non-core oil properties

Plans for 2000

- Continue focus on gas business profitability
- Build on recent success in the Alberta Foothills and increase exploration in northeastern British Columbia
- Complete disposition of non-core oil properties

Business Description

- Converts crude oil into refined products, including gasoline, diesel, jet fuel and asphalt
- Provides 18% of Canada's refining capacity for domestic markets
- Markets refined petroleum products and services through a nationwide network of retail and wholesale outlets
- Canada's second largest marketer, with a 17% share of the refined products market
- Manufactures and markets high-quality specialty lubricants

Strategy

- Generate superior returns and growth by building on our strengths in niche refining markets, being the brand of choice for Canadian consumers, and maximizing sales of high-margin specialty products

1999 Achievements

- Boosted refinery crude unit utilization to 100% from 95% in 1998
- Matched 1998 record asphalt sales of 1.4 billion litres
- Total petroleum product sales increased 4.4%, outpacing market demand increase of 1.3%
- Average throughput per retail site reached 3.6 million litres, highest among the national integrateds' total networks
- Increased total sales of lubricants by 8.0%, to 725 million litres

Plans for 2000

- Maintain high utilization and enhance focus on safe, reliable and efficient plant operations
- Position refineries to meet future environmental regulations, particularly for fuel reformulation
- Further increase throughput per retail site and non-petroleum revenue
- Further increase sales of high-margin lubricants through North American distribution agreement with Witco Corp.

TO OUR SHAREHOLDERS

Petro-Canada delivered sharply improved results in 1999, gaining a strong boost from higher commodity prices.

With robust cash flow adding to our solid financial position, we will invest $1.2 billion in 2000 to strengthen our core businesses and advance our growth opportunities. At the same time, we will focus on improving the cost-competitiveness, reliability and financial performance of our operations.

Shareholders have not yet been appropriately rewarded for their faith in our Company. The industry as a whole has been out of favour in equity markets, despite rising commodity prices. But we must also acknowledge that Petro-Canada has not fully realized the potential of its outstanding portfolio of assets and opportunities to create value for investors.

We intend to deliver on Petro-Canada's potential, through a disciplined effort to improve performance and a focused investment approach to ensure profitable growth.

Improved Business Environment

A dramatic rise in oil prices and stronger natural gas prices created a much-improved climate for the oil industry by the end of 1999. Prices for West Texas Intermediate benchmark crude rose from a low of U.S.$11.37 in February to U.S.$27.07 in November. Higher prices were the key factor enabling our Upstream business to achieve record earnings from operations of $243 million, up from $29 million in 1998.

Higher commodity prices had the opposite effect in the Downstream, raising feedstock and fuel costs. Efforts to recover higher costs met resistance in the marketplace, especially as these costs – and therefore the price at the pump – continued to rise through the year. Successful marketing efforts increased sales volumes. However, historically low refining margins and lower differentials for heavy feedstock reduced earnings. Our Downstream had earnings from operations of $115 million, down from $204 million a year earlier.

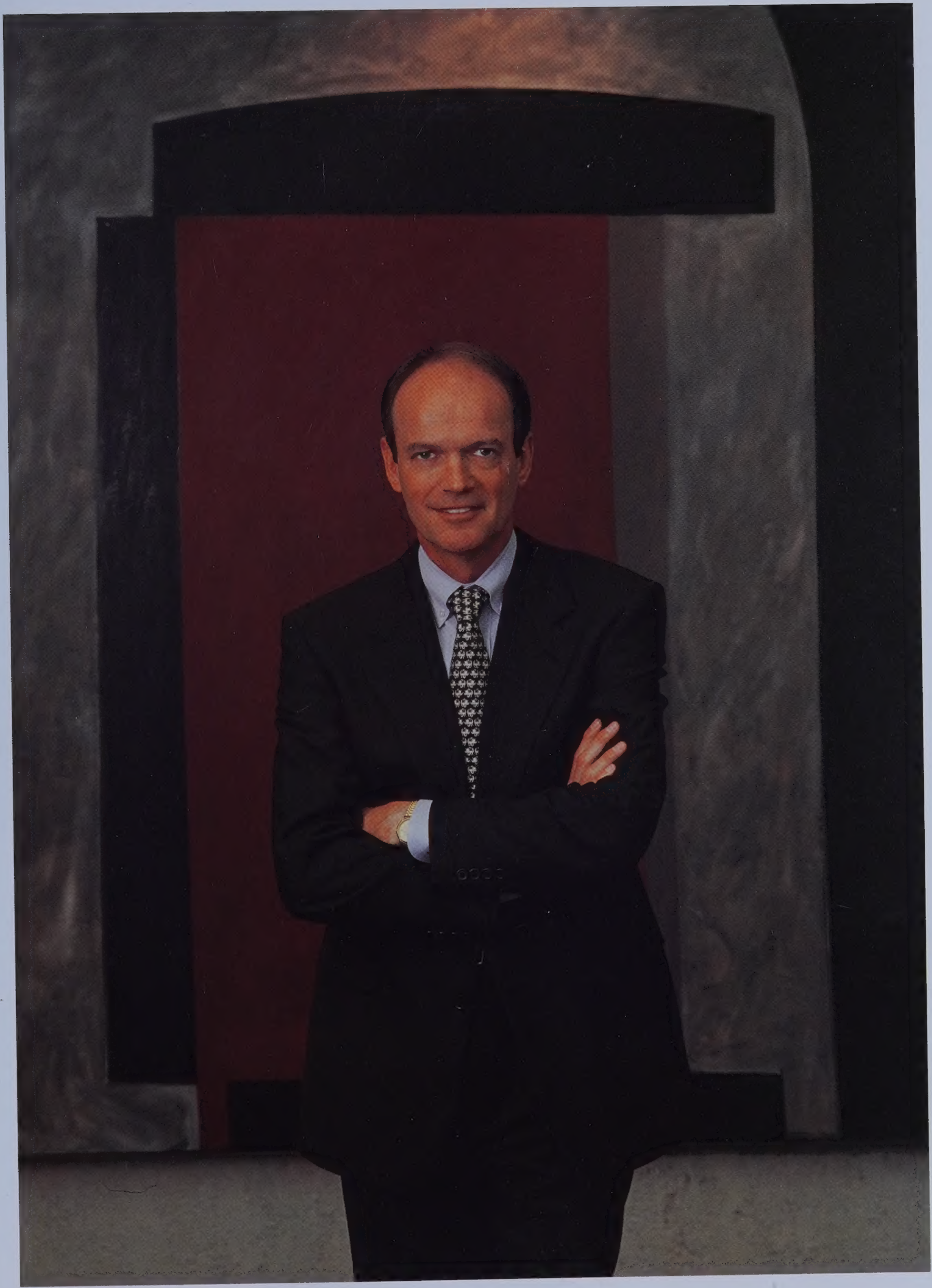
Overall, the combination of higher oil and gas prices and improved product sales and mix led to net earnings of $233 million for 1999, up from $95 million in 1998. Cash flow was $964 million, up from $830 million a year earlier.

Recognizing our strong financial position, higher cash flow, and our shareholders' need for improved returns, the Board approved a 25 per cent increase in the dividend on our stock in the fourth quarter.

Operational Highlights in 1999

Petro-Canada continued to strengthen and grow its core businesses of Grand Banks oil, oil sands, natural gas, and refining and marketing during 1999.

By year end, the Hibernia oil field was producing 150 000 barrels per day, of which 30 000 accrue to Petro-Canada. Production earlier in the year was limited by startup problems with the platform's gas compressors, which came on stream in January. When gas injection is unavailable, oil production must be restricted, and Petro-Canada's production over the year averaged less than



Ron Brenneman became President and Chief Executive Officer on January 10, 2000. A Canadian coming from a 31-year career in a large Canadian and international oil organization, he brings to Petro-Canada a global perspective and deep experience spanning upstream, downstream and corporate leadership.

expected at 20 000 barrels per day. Reservoir performance was excellent, however, leading us to raise our estimates of Hibernia's ultimate reserves by 19 per cent, to 730 million barrels (146 million barrels to Petro-Canada).

Preparations continued for production at Terra Nova, which is now expected to be on stream by the second quarter of 2001. "Glory holes" were completed to protect subsea wellheads, and production wells began drilling in July, while the production vessel nears completion. Offshore drilling in 1999 included encouraging delineation wells at White Rose and Hebron/Ben Nevis.

In Western Canada, we more than replaced our natural gas production with new reserves through the drill bit, and held production steady despite some asset sales. In particular, our Wildcat Hills/Benjamin Creek play continued to add substantial reserves and production.

In the Downstream, Petro-Canada continued to gain momentum in the marketplace. Refined product sales volumes rose 4.4 per cent, outpacing market demand growth of 1.3 per cent.

In May, we launched new clean gasoline blends using our TACTROL deposit control additive. SuperClean gasoline, together with WinterGas and other products targeted to Canadian driving conditions, achieved strong market response. Our Petro-Points loyalty program continued to expand, engaging 4.3 million households by year end. Throughput per retail site rose again as the roll-out of our efficient new-image outlets continued.

A Disciplined Approach to Performance

The Company's overall performance and profitability will be the focus of management's immediate attention. Employees achieved improvement in several controllable areas in 1999. Price realizations and operating costs improved in natural gas, as did Downstream per-unit operating and overhead costs and contribution from non-petroleum products and services. Hibernia and Syncrude operating costs declined, with further reductions expected in 2000 and future years.

These gains are a good start, but Petro-Canada's overall cost performance and projections are not what they should be. We are beginning the year 2000 with a detailed analysis of the company's cost structure to identify opportunities for improvement. Our aim is to achieve first-quartile cost performance in each of our businesses.

Reliability will also be a focal point in 2000 and beyond. Improving operating reliability by minimizing unplanned shutdowns is the most effective way we can add volumes. We believe Hibernia is approaching steady-state reliability, and we continue to emphasize reliability in Western Canada Upstream operations. While our Downstream achieved 100 per cent crude capacity utilization in 1999, the reliability of the value-adding conversion units did not approach that level. Improvement in reliability will have a direct payoff in profitability.

Ron Brenneman
President and Chief Executive Officer

Jim Stanford
Chairman of the Board

Strategic Focus

The Company has a broad base of assets in its core businesses. The profitability and potential of these assets will be examined closely to ensure each is contributing to overall bottom-line results. Petro-Canada also has a tremendous portfolio of future opportunities, and the financial strength to pursue them. We will focus on those opportunities that play to our strengths, and where our position and capabilities give us competitive advantage.

Many potential Upstream opportunities have already been identified. Proved reserves are booked only after development drilling is well advanced. But our total probable and possible reserves inventory available for development – on the Grand Banks, in the oil sands, in Western Canada and internationally – is well over 1.5 billion barrels, more than double the proved reserves on our books.

Grand Banks oil is the cornerstone of our growth strategy. We expect daily Hibernia production to average 135 000 barrels in 2000 and approach plateau levels of 160 000 barrels (32 000 to Petro-Canada) in 2001. Terra Nova will come on stream in 2001, with production at year end targeted at close to 130 000 barrels per day (37 000 to Petro-Canada). We are optimistic that further drilling and economic evaluation of White Rose and Hebron/Ben Nevis will confirm their attractiveness as major stand-alone developments.

Petro-Canada shares in every major oil discovery to date on the Grand Banks. So far, drilling has focused on the Jeanne d'Arc Basin, only one of several prospective basins off Newfoundland. In 2000, we will begin exploration in the Flemish Pass, a lightly explored basin in deeper water that is accessible with today's production technology. We will also drill new prospects in the Jeanne d'Arc.

Growth will also come from our other core businesses. We are increasing our focus on natural gas and oil sands in Western Canada, divesting most of our remaining conventional oil and our natural gas liquids business early in 2000. Capital spending on Western Canada conventional activity will rise by 40 per cent to nearly $400 million in 2000, mostly for gas exploration and development in the Alberta Foothills and northeastern British Columbia.

We are looking further afield for future resource additions. Seismic work began early in 2000 on large holdings acquired in 1999 in the Mackenzie Delta, in the Northwest Territories, and will begin this summer on the Scotian Shelf, offshore Nova Scotia. Both are longer-term, higher-risk plays with good potential. Further successful exploration in the Mackenzie Delta is needed to identify the threshold reserves required for construction of a pipeline to link the region to the North American grid. The Scotian Shelf acreage is in the vicinity of the Sable Gas development, which came on stream in 1999, providing infrastructure to access the United States market.

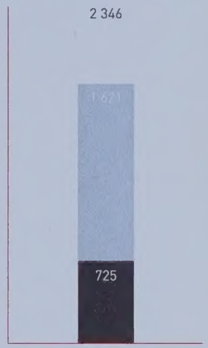
In oil sands, expansion of Syncrude will raise our share of production from 30 000 barrels per day in 2000 to more than 50 000 by 2007. We are actively evaluating an *in situ* opportunity on Petro-Canada lands at MacKay River, which could be an attractive development, beginning at 22 000 barrels per day or more.

We will take a measured approach in pursuing these Upstream opportunities – and others we may identify beyond our present portfolio – taking appropriate risk but driving to exceed cost of capital returns in any development we undertake.

In the Downstream, we will continue to leverage our brand strength and excellent refining network, and implement plans to realize the potential of our lubricants business. A major challenge in coming years will be preserving our competitive position and improving our cost structure while finding the most economic approach to the investment required to comply with new fuel regulations.

TOTAL RESERVES INVENTORY

Our large reserves inventory provides a strong base for future growth.



■ Proved reserves *(millions of barrels of oil equivalent)*

▨ Probable and possible reserves *(millions of barrels of oil equivalent)*

Our Second Quarter-Century

In closing, we would like to acknowledge the significant contribution of Tom Kierans over his four years as Chairman of the Board. Tom relinquished the position in January 2000, while remaining a director. We also thank Gerry Maier, a director from April 1995 to January 2000, for the benefit Petro-Canada gained from his experience and wisdom. In addition, Wesley Twiss retired as Executive Vice-President and Chief Financial Officer in January 2000. We thank Wesley for his 16 years of service, and welcome Harry Roberts to the Executive Leadership Team as our new Senior Vice-President and Chief Financial Officer. Harry joined Petro-Canada in 1989 following 15 years in the petroleum and financial industries, and was most recently Vice-President, Finance and Planning, and Treasurer.

Petro-Canada begins its second quarter-century in 2000. We are encouraged by the more positive fundamentals in our business environment and tremendously excited by the opportunities open to Petro-Canada. As our capable and committed employees celebrate our silver anniversary, we rededicate ourselves to our mission of building value for our shareholders and opportunity for our Company in the years ahead.

Ron Brenneman
President and Chief Executive Officer

Jim Stanford
Chairman of the Board

I had the privilege to serve as Chairman of the Board from 1996 to January 2000, when I stepped aside to enable the appointment of Jim Stanford as Chairman, in recognition of the very fine job he has done as President and Chief Executive Officer since 1993.

About a year ago, Jim expressed his desire to retire, and the Board began a search to identify a successor. I am very pleased we were able to recruit an individual with the superb qualifications of Ron Brenneman, who became President and Chief Executive Officer on January 10, 2000. With 31 years in upstream, downstream and corporate leadership roles, he has experience both broad and deep. And with international as well as Canadian experience in one of the world's largest integrated petroleum organizations, he brings a global perspective and a rich background to Petro-Canada.

On behalf of the Board, I want to commend and thank Jim Stanford for his tremendous contribution to Petro-Canada as President and CEO. Having joined Petro-Canada in 1978, he took the helm in January 1993, and led a dramatic financial turnaround. Setting a clear business direction, he earned Petro-Canada the respect of the financial world. And with his commitment to investing in the community and setting a high standard of corporate responsibility, he won for Petro-Canada an honoured place in Canadian society.

Tom Kierans
Director
Chairman of the Board (April 1996 to January 2000)

WE WILL PROVIDE PROFITABLE GROWTH AND SUPERIOR PERFORMANCE THROUGH OUR FOUR CORE BUSINESSES.

GRAND BANKS OIL
UNMATCHED POSITION

OIL SANDS
EXPANDING SYNCRUDE PRODUCTION

WESTERN CANADA NATURAL GAS
STRONG BASE, IMPROVING PERFORMANCE

DOWNSTREAM
CANADA'S BRAND OF CHOICE

Refinery
Lubricants plant

Petro-Canada operates 1 658 retail and 196 Petro-Pass sites across Canada.

GRAND BANKS OIL

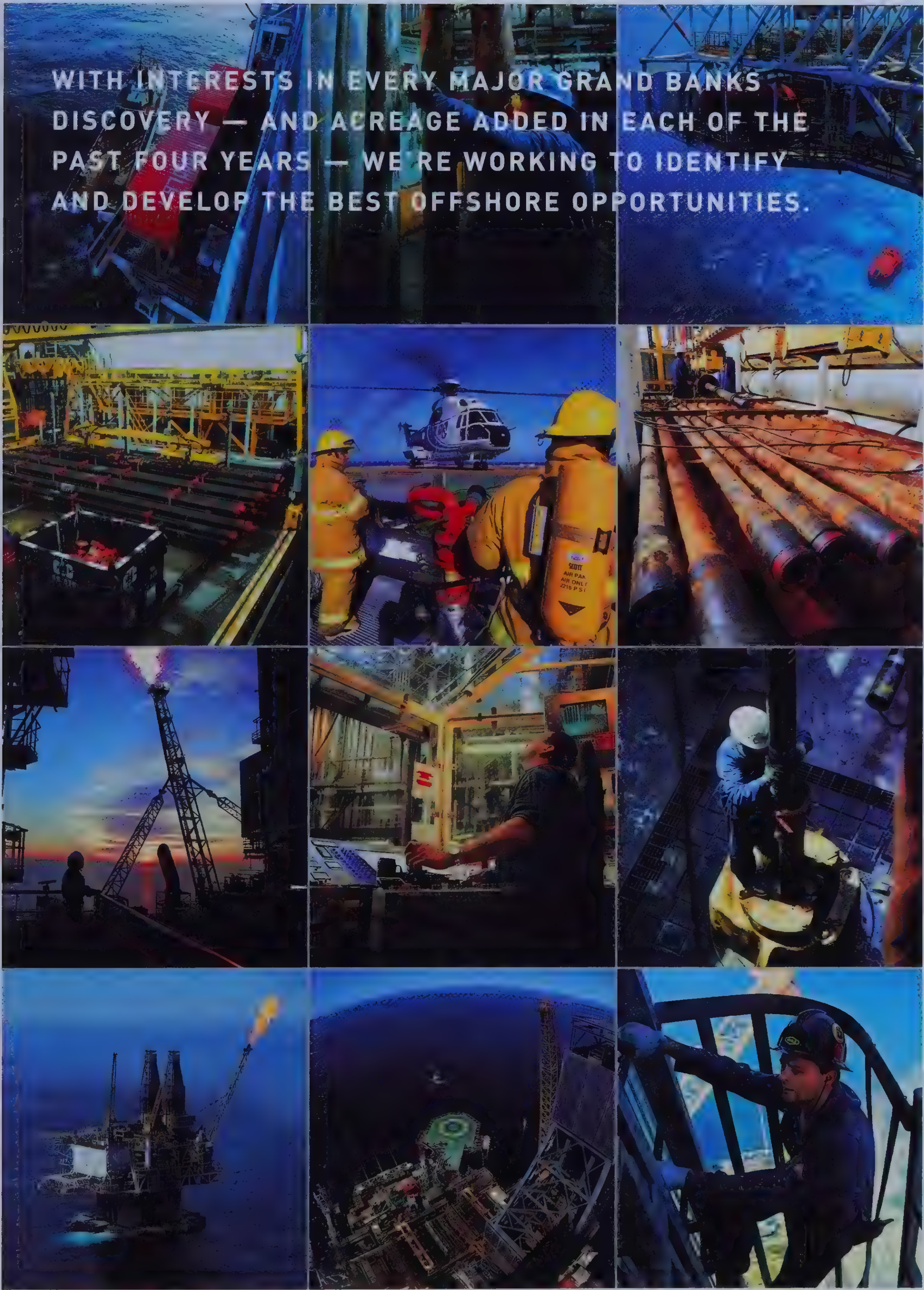
WE EXPECT TO PRODUCE UP TO 100 000 BARRELS OF OIL PER DAY FROM OFFSHORE NEWFOUNDLAND BY 2005.

In the Port of St. John's, the *Burin Sea* prepares for another voyage to support drilling in the Terra Nova field 350 kilometres distant. Five wells will be drilled this year, and first oil is expected by the second quarter of 2001.

BY THE END OF 2001, OUR SHARE OF HIBERNIA AND TERRA NOVA OIL IS EXPECTED TO BE CLOSE TO 70 000 BARRELS PER DAY.

Terra Nova's production and storage vessel — nearing completion in South Korea — will be able to process 140 000 barrels of oil per day, store 960 000 barrels and house up to 80 workers.

WITH INTERESTS IN EVERY MAJOR GRAND BANKS DISCOVERY — AND ACREAGE ADDED IN EACH OF THE PAST FOUR YEARS — WE'RE WORKING TO IDENTIFY AND DEVELOP THE BEST OFFSHORE OPPORTUNITIES.



OIL SANDS

EXPANSION OF SYNCRUDE WILL BOOST OUR SHARE OF SYNTHETIC CRUDE FROM 26 700 BARRELS PER DAY TO MORE THAN 50 000 BY 2007.

The large bitumen deposits now being tapped from Syncrude's North Mine will replace declining production from the East Mine. New volumes from the North Mine helped Syncrude post record production in 1999.

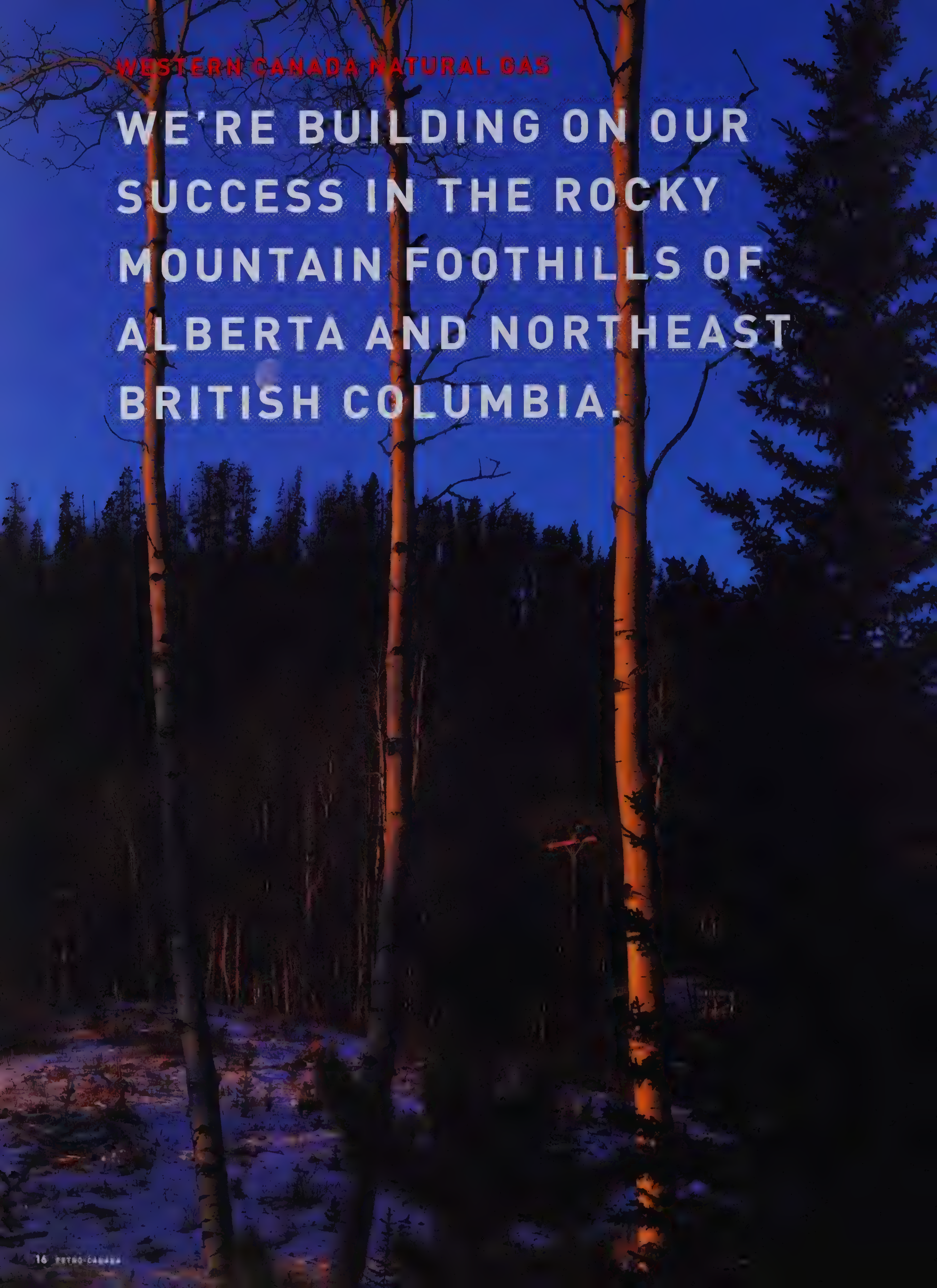
Hydraulic shovels (top) scoop more bitumen per load, saving time, energy and money; *in situ* production at Mackay River (bottom) could begin at 22 000 barrels per day or more.

THE SECOND PHASE OF THE NORTH MINE DEVELOPMENT WAS COMPLETED IN 1999.

THE AURORA MINE IS SCHEDULED FOR STARTUP LATE IN THE SECOND QUARTER OF 2000.

WESTERN CANADA NATURAL GAS

WE'RE BUILDING ON OUR SUCCESS IN THE ROCKY MOUNTAIN FOOTHILLS OF ALBERTA AND NORTHEAST BRITISH COLUMBIA.



In the Wildcat Hills/Benjamin Creek area, Petro-Canada has drilled 30 consecutive [illegible] gas wells in the past three years, including 10 in 1999.

To handle increasing gas volumes, we've filled our Wildcat Hills gas plant (top and bottom) to capacity and built pipelines to nearby plants.

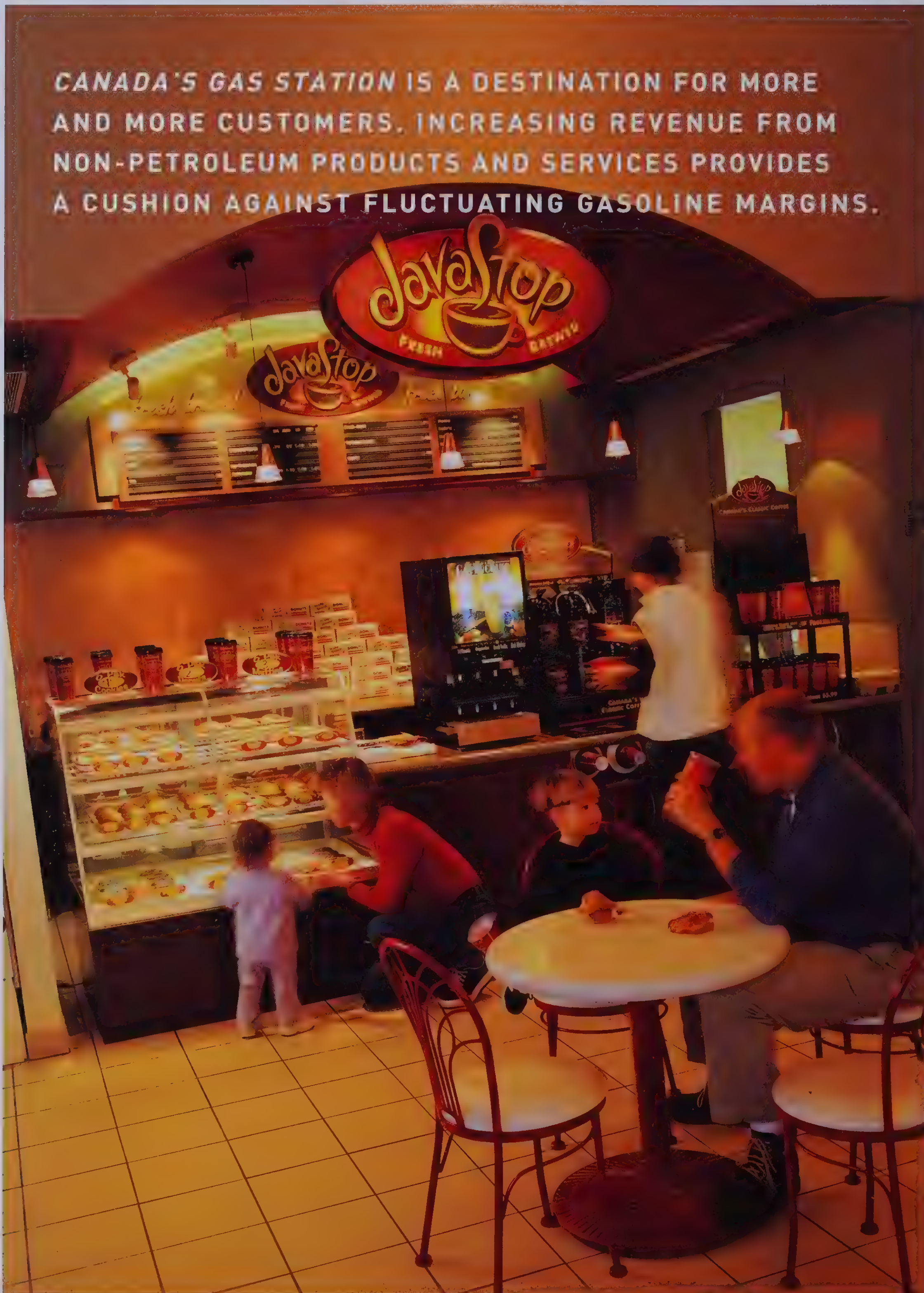

STRONG FOOTHILLS PERFORMANCE HELPED SUSTAIN GAS VOLUMES ABOVE 700 MILLION CUBIC FEET PER DAY, WHILE RESERVE ADDITIONS TOTALED 106 PER CENT OF 1999 PRODUCTION.


MORE THAN 40 FOOTHILLS WELLS ARE PLANNED FOR 2000.

DOWNSTREAM

PETRO-CANADA IS THE BRAND OF CHOICE IN THE HIGHLY COMPETITIVE CANADIAN FUELS MARKET.

In 1999, we again increased our gasoline sales per retail site, boosted refinery volumes and improved sales of high-margin specialty lubricants.



"Fill 'er Up" takes on a whole new meaning at a new-image site in Scarborough, Ontario, as a family enjoys our JavaStop coffee and freshly baked pastries. New brands have helped Petro-Canada boost revenue in key non-petroleum sales categories.

IT'S ALL ABOUT BRAND, AND WE CONTINUE TO DIFFERENTIATE PETRO-CANADA FROM THE COMPETITION WITH UNPARALLELED PRODUCTS AND SERVICES.

FINANCIAL AND OPERATING REVIEW

MANAGEMENT'S DISCUSSION & ANALYSIS

FINANCIAL STATEMENTS

GLOSSARY OF FINANCIAL TERMS AND RATIOS

Terms

BARREL OF OIL EQUIVALENT: Natural gas production (excluding injectants) is converted using 10 000 cubic feet of gas for one barrel of oil.

CAPITAL EMPLOYED: Total of shareholders' equity and debt, less related foreign currency translation adjustment.

CASH FLOW: Cash flow from operations before changes in non-cash working capital items.

DEBT: Long-term debt including current portion.

EARNINGS FROM OPERATIONS: Earnings before gains (losses) on asset sales.

OPERATING EXPENSES: Producing, refining and marketing expenses.

OVERHEAD EXPENSES: General and administrative expenses.

Ratios

RETURN ON CAPITAL EMPLOYED: Net earnings plus after-tax interest expense divided by average capital employed. Measures net earnings relative to the asset base.

OPERATING RETURN ON CAPITAL EMPLOYED: Earnings from operations plus after-tax interest expense divided by average capital employed. Measures operating earnings relative to the asset base.

RETURN ON EQUITY: Net earnings divided by an average shareholders' equity. Measures the return earned by shareholders on their investment in the Company.

CASH FLOW RETURN ON CAPITAL EMPLOYED: Cash flow plus after-tax interest expense divided by average capital employed. Measures cash flow generated relative to the asset base.

CURRENT RATIO: Current assets divided by current liabilities. Reflects the Company's short-term liquidity and its ability to pay short-term debts.

INTEREST COVERAGE: Measures the Company's ability to cover interest charges on debt.

Earnings basis: Earnings before interest expense and provision for income taxes divided by interest expense plus capitalized interest.

EBITDAX basis: Earnings before interest expense, income taxes, depreciation, depletion and amortization and exploration expenses divided by interest expense plus capitalized interest.

Cash flow basis: Cash flow before interest expense and current income taxes divided by interest expense plus capitalized interest.

DEBT TO CASH FLOW: Debt divided by cash flow. Indicates the Company's ability to discharge its outstanding debt.

DEBT TO DEBT PLUS EQUITY: Debt divided by debt plus equity. Indicates the relative amount of debt in the Company's capital structure. Measures financial strength.

Conversion Factors

To conform with common usage, imperial units of measurement are used in this report to describe exploration and production, while metric units are used for refining and marketing. Dollars are Canadian unless otherwise stated.

1 cubic metre (liquids) = 6.29 barrels
1 cubic metre (natural gas) = 35.31 cubic feet
1 litre = 0.22 imperial gallon
1 hectare = 2.47 acres
1 cubic metre = 1 000 litres

Management's Discussion & Analysis

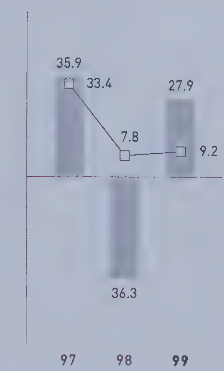
Introduction

This Management's Discussion & Analysis includes the results of 1999 activities and a discussion of management's outlook for the business in 2000 and beyond. Accompanying the text are graphs of our *value drivers*, which we regard as key measures of performance in each component of the business.

Petro-Canada follows the principles of value-based management, assessing the value-creating potential of existing businesses and new opportunities. We regularly evaluate the performance of all of the Company's assets, and divest or acquire assets where we believe we can improve the capability of the business portfolio to create value.

SHAREHOLDER VALUE

Shareholder value grew 28 per cent through market appreciation and higher dividends.



One-year return *(per cent)*

Three-year average *(per cent)*

– Shareholder value measures the change in the Petro-Canada share price, plus dividend returns.

RESULTS OF OPERATIONS

Business Conditions in 1999 and Outlook for 2000

Petro-Canada's financial results are significantly influenced by external business environment factors including crude oil and natural gas prices, refined product margins, the Canadian/U.S. dollar exchange rate and the demand for natural gas and refined petroleum products.

Business Conditions in 1999

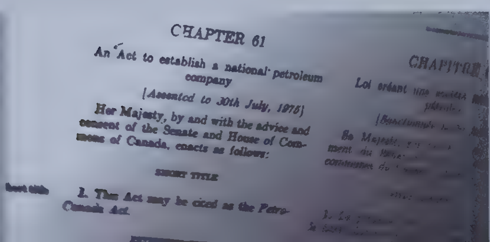
The prices of crude oil and natural gas have a major effect on the financial results of companies in the oil and gas sector. While the natural gas price largely affects results in the upstream, the price of crude oil significantly affects both upstream and downstream businesses, usually in opposite ways. A high crude price benefits upstream producers, but it negatively affects downstream operations as feedstock costs for refineries increase.

The price of crude oil increased dramatically during 1999. The price of benchmark West Texas Intermediate (WTI) oil averaged U.S.$19.30 per barrel on the New York Mercantile Exchange (NYMEX), an increase of 34 per cent from the 1998 average price of U.S.$14.40. The transition to higher crude prices was not, however, a smooth one. The WTI price touched bottom at U.S.$11.37 on February 16 and reached a peak of U.S.$27.07 on November 22, its highest value since January 1991.

The Management's Discussion & Analysis contains forward-looking statements, including references to: future capital and other expenditures (including the amount, nature and sources of funding), oil and gas production levels and the sources of their growth, tax and royalty rates, oil and gas prices, the Canadian dollar exchange rate, interest rates, refining and marketing margins, demand for refined petroleum products, planned facilities construction and expansion, retail site throughputs, pre-production and operating costs, proved and probable reserves, natural gas export capacity, results of exploration and development activities, acquisition and disposition of resource properties, and the dates by which certain areas will be developed or will come on stream. These forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; refining and marketing margins; the ability to produce and transport crude oil and natural gas to markets; the results of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; changes in environmental and other regulations; risks attendant with oil and gas operations; and other factors, many of which are beyond our control.

PETRO-CANADA H[illegible]

On July 30, 2000, Petro-Canada celebrates its silver anniversary. Accompanying the Management's Discussion & Analysis are some of the highlights of our 25-year journey, along with a few of the employees who've contributed to our success over the years.


CHAPTER 61

An Act to establish a national petroleum company

[Assented to 30th July, 1975]

Her Majesty, by and with the advice and consent of the Senate and House of Commons of Canada, enacts as follows:

SHORT TITLE

1. This Act may be cited as the Petro-Canada Act.

The impact of rising international oil prices on Canadian crude prices was amplified somewhat by the weakness of the Canadian dollar relative to the U.S. dollar in 1999. The Canadian dollar exchange rate gradually increased from a low of 65.37 U.S. cents on January 19 to 69.29 U.S. cents on December 31. Petro-Canada's posted prices for benchmark Edmonton Light crude oil averaged $27.59 per barrel during 1999, up almost 36 per cent from 1998. By December, the postings for Edmonton Light averaged $38.81 per barrel.

Prices for natural gas liquids tend to track crude oil prices closely, and propane and butane prices therefore increased sharply in 1999 over 1998 values.

Natural gas prices also increased in 1999. The average benchmark NYMEX price of natural gas at the Henry Hub in Louisiana improved to U.S.$2.27 per million BTUs from U.S.$2.14 in 1998. Warm winter weather and an abundance of gas in storage kept Henry Hub prices below U.S.$2.00 per million BTUs for the first four months of the year. However, as the storage overhang gradually disappeared and concerns about gas deliverability grew, so too did the price of gas, reaching a high of U.S.$3.09 at the Henry Hub on October 27 from a low of U.S.$1.63 on February 26.

Recent natural gas pipeline expansions have benefited Canadian gas producers by removing export capacity constraints and narrowing the differential between U.S. and Canadian gas prices. The Henry Hub-AECO C differential, which averaged U.S.$0.77 per million BTUs in 1998, narrowed substantially to an average of U.S.$0.28 during 1999. This pushed the average gas price at the AECO C Hub in Alberta up to $3.09 per thousand cubic feet, a major gain over the 1998 average of $2.12. From its lowest average level of $2.47 per thousand cubic feet in March, the AECO C price climbed to a high of $4.13 in November. In December, the average price decreased to $3.47 per thousand cubic feet because of the warm start to the winter. Reflecting these price developments, the Alberta Blended Plant Gate price averaged $2.58 per thousand cubic feet in 1999, compared with an average of $2.02 in 1998.

In the downstream industry, the key external factors affecting financial results are the volatility of crude oil prices, industry refining margins, movement in crude oil price differentials, overall demand for refined petroleum products and the degree of market competition.

The rapid rise in crude oil prices combined with ample inventories of refined petroleum products put refining margins under downward pressure in 1999. During the first half of the year, severely depressed heating oil prices dragged down overall refining margins. For example, the New York Harbor *3-2-1 crack spread* is a benchmark indicator for the margin available to refiners. In 1999, the average NYH 3-2-1 crack spread was U.S.$2.51 per barrel compared with an average over the previous three years of U.S.$3.43, a drop of 27 per cent.

The spread between the price of light crude oil and heavy crude oil was unusually narrow in 1999. Internationally, the price differential between benchmark crudes such as North Sea Brent (light) and Mexican Maya (heavy) narrowed to U.S.$3.44 per barrel from an average of U.S.$4.03 in 1998. Canadian light/heavy crude price differentials mirrored this trend. Based on Petro-Canada's posted prices, the spread between the prices of benchmark Edmonton Light and Bow River (heavy) crudes narrowed in 1999 to $4.32 per barrel from an average of $5.77 per barrel in 1998, although the spread widened in the latter part of the year.

Parliament passes the Petro-Canada Act, establishing a Crown corporation to create a strong Canadian presence in the oil industry and identify new Canadian energy resources. Petro-Canada to take over federal government interests in Syncrude and Panarctic Oils.

Another factor that affected the downstream industry was the narrow price differential between WTI and lower-priced North Sea Brent crude oil. The differential narrowed to U.S.$1.37 per barrel from an average of U.S.$1.68 in 1998. By December, the gap had narrowed to U.S.$0.52 per barrel compared with U.S.$1.44 a year earlier. This change had a negative impact on refineries that import crude from the Atlantic Basin, such as Petro-Canada's facilities in Montreal and Oakville.

Growth in Canadian refined petroleum product sales slowed to 1.3 per cent in 1999 from 2.2 per cent in 1998. The growth in 1999 was led by sales in motor gasoline, diesel and jet fuel.

Outlook for Business Conditions in 2000

Prices for energy commodities are influenced by a number of factors, including developments in supply and demand, weather, political events and the level of industry inventories. Analysts expect crude oil prices to remain volatile in 2000, given very low commercial oil stocks and uncertainty over OPEC's course of action after the current quota agreement expires in March.

Estimates indicate the production cuts implemented so far have subtracted in excess of 4.0 million barrels per day from the world oil market — OPEC's tightest wilful squeeze on world oil supply since the 1973-74 oil shock. As a result, during the first two months of 2000, the price of WTI has averaged U.S.$28.16, up from an average of U.S.$12.02 per barrel in the first two months of 1999. On the other hand, should OPEC's discipline waver or global oil demand weaken, international oil prices could quickly soften again. Given this uncertainty, we believe it is prudent to test business plans against a range of possible oil prices, centred around the historical average since 1986 of about U.S.$19.00 per barrel for WTI.

Petro-Canada has assumed that the Alberta Blended Plant Gate price for natural gas in 2000 will strengthen somewhat from the average of $2.58 in 1999. The expectation of stronger Canadian prices assumes that the positive impact of recent increases in pipeline capacity will continue in 2000. We also assume that additional export capacity from the new Alliance Pipeline will be available on November 1, keeping the differential between U.S. and Canadian gas prices fairly narrow. In the first two months of 2000, the differential between U.S. gas prices at the Henry Hub and Canadian prices at the AECO C Hub averaged U.S.$0.33 per million BTUs compared with an average of U.S.$0.12 in the first two months of 1999.

Expectations of continued positive Canadian economic conditions lead us to anticipate growth in domestic sales of refined products in 2000 in line with the 1.3 per cent experienced in 1999. Margins on the sale of products will depend on the movement in crude oil prices over the year, the supply/demand balance and competition in the marketplace.

Petro-Canada invests in East Coast exploration programs operated by others, providing funds to pick up the pace of exploration. To gain a base of cash flow and operating expertise, Petro-Canada buys U.S.-owned Atlantic Richfield Canada, adding producing oil and natural gas properties in Western Canada, gas processing facilities, and some oil sands interests.

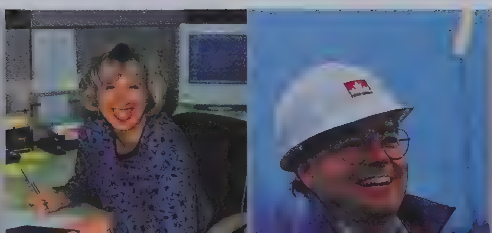
Sensitivities Affecting Net Earnings

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 1999 net earnings had these changes occurred. We base these calculations on business conditions, production and sales volumes realized in 1999.

Factor	1999 average	Change (+/-)	Approximate Change (+/-) in Net Earnings[1] (millions of Canadian dollars)
Upstream Sector			
WTI benchmark crude oil price	U.S. $19.30 per barrel	U.S. $1.00 per barrel	24
Price received for natural gas[2]	$2.59 per thousand cubic feet	$0.10 per thousand cubic feet	9
Production of crude oil and liquids	95 300 barrels per day	1 000 barrels per day	2
Production of natural gas available for sale	719 million cubic feet per day	10 million cubic feet per day	2
Downstream Sector			
Refining and supply margin[3]	0.8 cents per litre	0.1 cent per litre	11
Marketing margin[3]	5.3 cents per litre	0.1 cent per litre	7
Light/heavy crude oil differential[4]	$4.32 per barrel	$1.00 per barrel	14
Corporate			
Canadian dollar exchange rate ($U.S. per $Cdn.)[5]	U.S. $0.6732	U.S. $0.01	(6)

1 The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors. The application of these factors may not necessarily lead to an accurate prediction of future results of operations. We undertake risk management initiatives from time to time that may affect these sensitivities.
2 Includes decrease in earnings of $2 million from straddle plant operations.
3 Revenue minus cost of sales.
4 The spread between the prices of benchmark Edmonton Light and Bow River crude oils.
5 A strengthening Canadian dollar versus the U.S. dollar has a negative effect on Petro-Canada's earnings.

Syncrude starts up as the world's largest oil sands plant, and ships its first synthetic crude oil.



Summarized Financial Results

Financial Results (millions of dollars, unless otherwise indicated)

	1999	1998	1997
Earnings from operations before reorganization costs	**236**	130	314
Reorganization costs	**—**	(42)	—
Gains (losses) on sale of assets	**(3)**	7	(8)
Net earnings	**233**	95	306
Earnings per share (dollars)	**0.86**	0.35	1.13
Cash flow[1]	**964**	830	1 263
Cash flow per share (dollars)	**3.55**	3.06	4.66
Return on capital employed (per cent)	**5.6**	3.0	6.8
Average capital employed	**5 630**	5 536	5 406
Return on equity (per cent)	**5.8**	2.4	8.0
Debt	**1 711**	1 829	1 741
Cash and short-term investments	**206**	431	75

1 Cash flow from operations before changes in non-cash working capital items.

1999 Compared with 1998

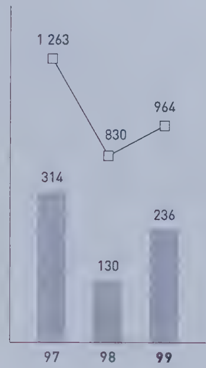
Petro-Canada delivered considerably improved financial results in 1999, with net earnings of $233 million, up 145 per cent from 1998 earnings of $95 million. The sharp rise in commodity prices contributed to a substantial improvement in Upstream results, although the rising crude oil price created a very difficult business environment in the Downstream. Cash flow increased to $964 million from $830 million in 1998, due primarily to higher earnings and reduced current income taxes.

Earnings from operations increased by $106 million in 1999, to $236 million from $130 million in 1998, as higher operating earnings in the Upstream more than offset decreases in the Downstream and in Shared Services. Upstream operating earnings rose by $214 million in 1999, to $243 million, due primarily to the rise in oil and gas prices. In the Downstream, operating earnings declined by $89 million, to $115 million, as a $55 million improvement in controllable elements, primarily sales volumes and product mix, helped to offset the negative year over year impact of $144 million caused by the difficult business environment. Shared Services net expenses increased in 1999, to $122 million from $103 million a year earlier, due to higher interest expense and general and administrative costs. 1998 net earnings were affected by a one-time reorganization charge of $42 million.

Petro-Canada's return on capital employed improved considerably in 1999, due primarily to increased earnings, rising to 5.6 per cent from 3.0 per cent in 1998. An ongoing focus of management is to seek improvement in the return on capital employed. While returns are subject to volatile commodity prices, we continue to focus on those elements of the business that are controllable and can improve earnings, such as expenses and volumes.

OPERATING EARNINGS AND CASH FLOW

Earnings and cash flow were up sharply but short of 1997's record performance.



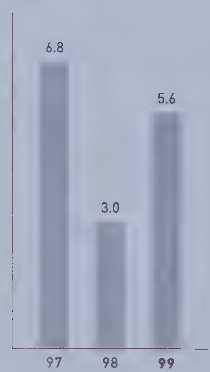
Earnings from operations *($ millions)*

☐ Cash flow *($ millions)*

- 1998 earnings are before reorganization costs.

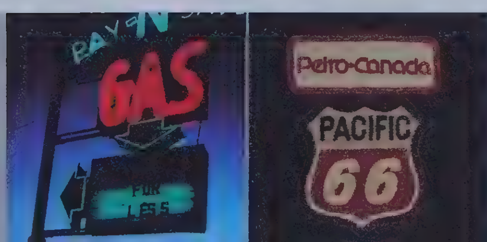
RETURN ON CAPITAL EMPLOYED

Higher earnings led to improved return on capital employed.



Return on capital employed *(per cent)*

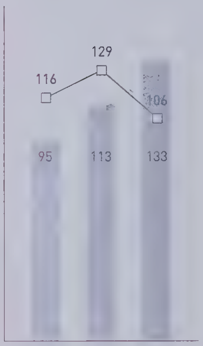
Petro-Canada buys U.S.-controlled Pacific Petroleums, adding more oil and gas properties and, for the first time, downstream operations: a small refinery and a marketing network. Petro-Canada shares in the Hibernia oil discovery off Newfoundland and major gas finds off Nova Scotia.



Upstream Sector Review

RESERVE REPLACEMENT

The Upstream again more than replaced production with new reserves.



Total conventional oil and gas *(per cent)*

☐ Natural gas *(per cent)*

- Excludes acquisitions and divestitures.
- Excludes Syncrude.

Overview of Operations

Petro-Canada's core Upstream businesses include Grand Banks oil, Western Canada natural gas, and oil sands interests, complemented by oil production in Western Canada, Norway and Algeria. Improved financial results and a strong balance sheet enable us to develop our core assets through an aggressive investment program, while carefully evaluating a range of opportunities for generating new growth prospects beyond these base assets.

Petro-Canada's production growth profile is heavily weighted toward the Grand Banks, offshore Newfoundland, offering investors excellent leverage to this developing oil region. We have a 20 per cent share in the landmark Hibernia oil development now on production, a 29 per cent interest as operator of the Terra Nova development under construction, and significant interests in every major oil discovery made in the region to date.

The Western Canada Sedimentary Basin offers Petro-Canada more attractive opportunities in natural gas than it does in conventional oil production. We are continuing our exit strategy from conventional oil in the area, while remaining one of the largest producers of natural gas. Petro-Canada is investing in natural gas at a level commensurate with the opportunities, with considerable success in the Alberta Foothills.

Petro-Canada also has a strategic stake in Canada's vast oil sands resources, with a 12 per cent share of Syncrude, the world's largest oil sands mining operation, and further large prospective *in situ* oil sands landholdings in the region. Independent reservoir engineering consultants conduct annual technical audits of one-third of Petro-Canada's proved oil and natural gas reserves on a rotational basis. In addition, Arthur Andersen LLP, as contract auditor, tests on an annual basis non-engineering management control processes we use in establishing reserves.

Petro-Canada continues to divest non-core assets in order to focus on those areas with the best long-term growth prospects. Future oil production will increasingly come from the Grand Banks and the oil sands, where large reserves generate good financial returns and potential for growth.

Upstream Sector 1999 Results

Financial Results (millions of dollars, unless otherwise indicated)

	1999	1998	1997
Earnings from operations	**243**	29	188
Gains (losses) on asset sales	**6**	30	(2)
Net earnings	**249**	59	186
Cash flow	**885**	516	900
Return on capital employed (per cent)	**7.3**	1.8	5.7
Cash flow return on capital employed (per cent)	**25.9**	15.7	27.4
Average capital employed	**3 416**	3 288	3 284

1999 Compared with 1998

Petro-Canada achieved record Upstream earnings of $249 million in 1999, up over 300 per cent from 1998. The greatest factor in the improvement in earnings was the significant rise in oil and gas prices over the year. Also contributing to the increase were lower operating costs and exploration expenses, which more than offset the negative impacts of lower volumes and a $16 million increase in Upstream hedging losses, to $35 million in 1999. Upstream cash flow increased by 72 per cent, due to the increase in earnings.

Petro-Canada drills its first offshore wells as operator of an exploration program off Labrador.

Total production averaged 167 200 barrels of oil equivalent per day, consisting of 95 300 barrels of oil and liquids and 719 million cubic feet of natural gas. Production declined somewhat from 173 300 barrels of oil equivalent in 1998, as lower conventional oil production in Western Canada more than offset increased volumes from Hibernia and Syncrude. Western Canada conventional oil production declined sharply due to the sale in late 1998 of four significant oil producing properties, as well as smaller oil property sales during 1999 and natural decline. In total, asset rationalization in 1998 and 1999 reduced daily production volumes by 11 000 barrels of oil and liquids and 12 million cubic feet of natural gas.

While production decreased in 1999, proved reserves were virtually unchanged at 725 million barrels of oil equivalent, as discoveries, extensions, and positive revisions equaled production and net sales. Increased reserves at Hibernia offset a decrease in Western Canada liquids reserves.

Including the effects of hedging activities, Petro-Canada's average price received for crude oil and field natural gas liquids production in 1999 was $24.58 per barrel, up from $17.72 a year earlier. Our average price received for natural gas was $2.59 per thousand cubic feet, up from $1.96 in 1998.

Grand Banks Oil

Hibernia, the first oil development on the Grand Banks, moved from startup to full-scale production in 1999. Reservoir porosity and permeability, well productivity, and oil quality all continued to exceed expectations, although a series of operational difficulties on the platform led to total production being somewhat lower than had been anticipated. Nevertheless, Petro-Canada's 20 per cent ownership share in Hibernia yielded 20 000 barrels of oil per day, a 54 per cent increase from 1998. Furthermore, Petro-Canada's share of production averaged over 30 000 barrels per day in November and December. At the end of 1999, Hibernia had 13 wells in operation, of which seven were oil producers, four were water injectors, and two were gas injectors.

Most of the 1999 operating difficulties at Hibernia related to the gas compression system. For resource management and environmental reasons, almost all of the natural gas produced with the oil at Hibernia must be injected back into the reservoir. When the gas compressors are not functioning, there are regulatory limits to how much oil can be produced. While Hibernia has been producing oil for two years, the gas compression system only came on stream early in 1999 and experienced a number of startup difficulties. This complex system was operating reliably in late 1999 and early 2000.

Hibernia unit operating costs fell in 1999 to $4.23 per barrel from $6.45 in 1998. Royalties and overhead expenses were $0.33 and $0.31 per barrel respectively.

Hibernia's economics improved further in late 1999, when Petro-Canada revised its estimate of ultimate gross proved plus probable reserves to 730 million barrels, up 19 per cent from the earlier estimate of 615 million barrels. Petro-Canada's 20 per cent share of Hibernia reserves is 146 million barrels, of which 12 million barrels had been produced by year end 1999.

The Petro-Canada operated Terra Nova development, in which we hold a 29 per cent interest, is the second major Grand Banks oil project. The floating production, storage and offloading vessel (FPSO), under construction in South Korea, neared completion in 1999. The production modules to be installed on the FPSO are being built in Newfoundland and in Scotland. Excavation of the "glory holes" to protect equipment on the ocean floor was completed in August, and pre-drilling of the production wells began in July. We expect first oil by the second quarter of 2001.

Petro-Canada participated in 1999 in ongoing work to determine the next Canadian offshore oil project. Five successful delineation wells were drilled, three at White Rose and two at Hebron/Ben Nevis.

Western Canada Natural Gas

Petro-Canada maintained natural gas production at 719 million cubic feet per day in 1999, in spite of the sale of properties producing about 12 million cubic feet per day. We improved performance on several key measures, and achieved a return on capital employed of nine per cent in this business.

OIL AND GAS PRODUCTION

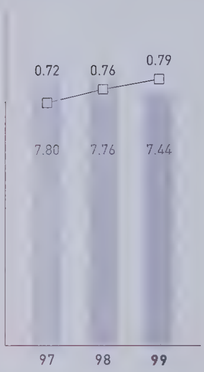
Production was down slightly in 1999, but is expected to increase in 2001 as Grand Banks and Syncrude volumes rise.

Upstream production *(thousands of barrels of oil equivalent per day)*

Acquisition of Belgian-owned Petrofina Canada gives Petro-Canada a refining and marketing presence in Eastern and Central Canada, and additional upstream properties in Western Canada.

WESTERN CANADA FINDING AND DEVELOPMENT COSTS

Finding and development costs remained competitive.



Western Canada conventional
($ per barrel of oil equivalent)

☐ Natural gas
($ per million cubic feet of gas equivalent)

- Three-year average for proved reserves.
- Excludes acquisitions and divestitures.
- Excludes Syncrude.

Gas price realizations approached first-quartile performance and operating costs dropped by eight per cent. Our three-year average finding and development costs for natural gas increased marginally from $0.76 per thousand cubic feet of gas equivalent to $0.79. While $0.79 is very competitive performance in the current business environment, we are still striving for improvement on this important measure. Including our Western Canada conventional oil properties, our three-year average finding and development costs fell from $7.76 per barrel of oil equivalent to $7.44 due to positive reserve revisions on oil properties. Despite a reduction in capital spending, we more than replaced gas production through drilling success, adding new reserves equivalent to 106 per cent of 1999 production. Total gas reserves declined slightly, however, from 2 495 billion cubic feet to 2 481, due to net sales of producing properties.

The Alberta Foothills natural gas business continues to deliver excellent results. In the Benjamin Creek area, we drilled Petro-Canada's two best Western Canada wells ever in 1999, measured by net pay (the thickness of the productive sections of the reservoir). We added 147 billion cubic feet of proved reserves in the Wildcat Hills/Benjamin Creek area, and increased production by 25 million cubic feet per day, up 50 per cent from 1998 levels. To process this rapidly increasing production, we have filled the Wildcat Hills gas plant to its capacity of 125 million cubic feet per day, and built pipelines to carry additional volumes to other nearby plants. Petro-Canada also acquired a significant new land position in the West Bearberry (Fallen Timber) area of the Foothills, and saw positive results from seismic surveys and the first well drilled.

Petro-Canada's second major gas production theatre is in northeastern British Columbia. This region has provided steady production and good cash flow. During 1999, we completed comprehensive technical studies on our assets in the region, to develop an investment strategy targeting our best value-adding opportunities. Based on the results, we have increased the exploration and development budget for northeastern British Columbia in 2000.

A key near-term goal for Petro-Canada is the achievement of superior profitability in our natural gas business. We have increased planned capital spending on natural gas by 40 per cent to almost $400 million for 2000, a level supported by the drilling opportunities we see.

Western Canada Oil and Field Natural Gas Liquids

Conventional oil production from Western Canada continued to decline in 1999, consistent with Petro-Canada's strategy to exit in stages from this business. We sold four large properties at the end of 1998, followed by a series of minor sales in 1999, reducing conventional oil production to an average of 24 700 barrels per day over the year, down from 38 300 barrels in 1998. Late in 1999, we announced plans to sell properties producing a further 17 000 barrels of oil per day and 20 million cubic feet per day of associated gas. Petro-Canada will retain two significant southern Alberta oil properties, Ferrier and Willesden Green. These assets are highly integrated into our west-central Alberta infrastructure and we will continue to invest in them.

Field natural gas liquids production was 11 700 barrels per day in 1999, down from 12 700 barrels in 1998.

Natural Gas Liquids

The natural gas liquids business consists of a liquids extraction plant at Empress, Alberta, a liquids pipeline from Empress to Winnipeg, and associated infrastructure. As oil and liquids prices rose more than natural gas prices did over the year, the business realized earnings after-tax of $18 million, compared with $11 million a year earlier. Consistent with Petro-Canada's continuing effort to narrow its focus on its core businesses, we announced the sale of the natural gas liquids business in the first quarter of 2000. The transaction will result in an after-tax gain of approximately $95 million, subject to adjustments on closing, the majority of which will be recognized in the first quarter.

Petro-Canada discovers oil at Valhalla, Alberta: the biggest new oil field of the 1980s in Western Canada.

Oil Sands

Through a 12 per cent share of the Syncrude joint venture, the world's largest oil sands development, as well as leaseholdings on almost 300 000 acres of other high-potential land, Petro-Canada intends to participate actively in further development of northern Alberta's vast oil sands resources.

Petro-Canada's share of record Syncrude production averaged 26 700 barrels per day of synthetic crude in 1999, up from 25 200 barrels in 1998. Syncrude continued to be a strong earnings generator, contributing $69 million in earnings in 1999, and generating a return on capital employed of 21 per cent. Operating costs at Syncrude were $12.83 per barrel in 1999, down from $13.42 in 1998, as the joint venture continues to reduce costs while proceeding with a multi-year expansion plan.

Drilling and evaluation continued in 1999 on our *in situ* oil sands leases at MacKay River in northern Alberta. Petro-Canada filed a commercial development application with the Alberta Energy and Utilities Board (AEUB) late in 1998 for a 22 000 barrel per day production facility at MacKay River. Stakeholder consultations took place in 1999 and the application was deemed complete by regulatory authorities in December. The AEUB decision is still forthcoming.

International

In Algeria, Petro-Canada produced 4 500 barrels per day (before Algerian royalties and the sharing of profit oil) from the Tamadanet field in 1999, unchanged from 1998, and evaluated four gas and liquids discoveries. Development plan applications have been filed for two fields. We plan two further exploration wells in 2000.

In neighbouring Tunisia, we completed a seismic program in 1999. Petro-Canada has exclusive rights to explore in the Tataouine block of south-central Tunisia, which we believe could be an extension of the productive Algerian Berkine basin across the border. In early 2000, we elected to proceed with the exploration license phase of the agreement, subject to Tunisian regulatory approval. We are planning two exploration wells within the next five years, with the first to be drilled in 2000.

In Norway, Petro-Canada's share of the Veslefrikk and Njord offshore oil fields contributed 7 700 barrels of oil per day in 1999, up from 7 400 in 1998, despite a planned dry docking of the Veslefrikk platform for maintenance. We also continue to gain value from our strategic alliance with Norsk Hydro, as we build expertise in offshore oil production.

Petro-Canada Conventional Netbacks and Earnings[1] (dollars per barrel of oil equivalent)

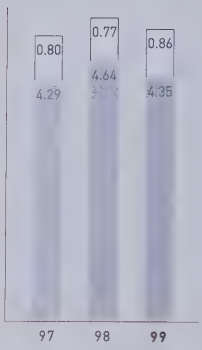
	1999	1998	1997
Revenue	**25.45**	18.17	21.66
Royalties	**4.04**	2.94	4.61
Operating expenses	**4.35**	4.64	4.29
Netback	**17.06**	10.59	12.76
Overhead expenses	**0.86**	0.77	0.80
Netback after overhead expenses	**16.20**	9.82	11.96
Oil hedging gains (losses)	**(0.58)**	—	0.13
Processing and other income	**0.10**	0.31	0.32
Exploration	**1.06**	1.46	1.06
DD&A, site restoration, and other capital costs	**7.73**	6.92	5.84
Earnings before taxes	**6.93**	1.75	5.51
Income and other taxes	**2.66**	1.42	3.16
Net earnings	**4.27**	0.33	2.35

1 Excludes Syncrude and all areas not currently in production.

Petro-Canada buys the refining and marketing end of British-owned BP Canada to enlarge its operations in Ontario and Quebec. Construction of Petro-Canada Centre completed in Calgary

UPSTREAM OPERATING AND OVERHEAD COSTS

Operating costs per barrel declined.



Unit operating costs
($ per barrel of oil equivalent)

☐ Unit overhead costs
($ per barrel of oil equivalent)

– Excludes Syncrude.

Revenue per barrel increased significantly in 1999, due to higher commodity prices. Royalties increased in line with the rising prices. Unit operating costs declined due to successful cost reduction initiatives, greater Hibernia volumes, and sales of higher-cost Western Canada oil properties. The increase in unit overhead expenses is mainly a result of the reduction in total production volume.

The increase in depreciation, depletion and amortization (DD&A) is largely due to the increased production from Hibernia. DD&A was $7.12 per barrel of oil equivalent for Western Canada conventional and $10.95 per barrel for Hibernia. Due to the increase in Hibernia reserves from 615 million barrels to 730 million, unit DD&A for Hibernia will be lower in 2000.

Upstream Outlook

Growth on the Grand Banks

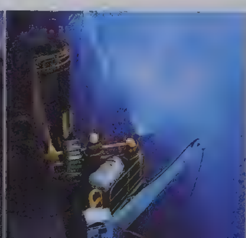
The next three years will see strong production and earnings growth from the Grand Banks, as Hibernia achieves peak production and Terra Nova comes on stream. Petro-Canada and the other participants are working to bring White Rose and Hebron/Ben Nevis to fruition as the next Grand Banks projects, further developing the Canadian offshore oil and gas industry. Petro-Canada has an average 22 per cent working interest in all offshore oil discoveries to date, giving us excellent leverage to this high-potential region.

Production from the Hibernia platform is expected to average approximately 135 000 barrels per day in 2000, of which Petro-Canada's share would be 27 000. In 2001, we expect production to reach a plateau level averaging 160 000 barrels per day, or 32 000 net to Petro-Canada, subject to regulatory approval. Operating costs are projected to drop below $3.00 per barrel in 2000 and fall still further in 2001. The Hibernia owners are also exploring possible infrastructure sharing opportunities with other East Coast projects to improve efficiency.

Hibernia platform drilling plans for 2000 include the first Avalon formation wells. The Avalon lies above the Hibernia formation, and contains more oil than the Hibernia, but its highly faulted, complex geology makes recovery more difficult.

The Terra Nova project will pass key milestones in 2000, as the first Petro-Canada operated Grand Banks development prepares for first oil by the second quarter of 2001. The FPSO vessel will be completed late in the first quarter of 2000 and will sail to Bull Arm, Newfoundland, where the production modules will be mounted. Six production wells will be complete by year end, and flowlines will be installed, ready to link up with the floating production vessel. First oil is now expected by the second quarter of 2001, a four-month delay from the original schedule, entailing an increase in the total budget of some ten per cent. However, we do not believe this delay will be material to the excellent overall economics of the project. In contrast to the gradual ramping up of production at Hibernia's fixed platform, we expect Terra Nova to achieve near-peak production shortly after startup. By the end of 2001, we expect production of 129 000 barrels per day, or 37 000 net to Petro-Canada, assuming regulatory approval of this production rate. We anticipate Terra Nova operating costs to be competitive, at less than $3.00 per barrel during peak production. Petro-Canada estimates gross reserves of 370 million barrels from two fault blocks to be produced over 15 years, with a further 100 million barrels possible from a third fault block, known as the Far East, that is as yet untested. We plan to drill a well in the Far East block in late 2000.

Petro-Canada's first big offshore discovery as operator: the Terra Nova oil field off Newfoundland. The government tells Petro-Canada to conduct its business in a solely commercial manner, focusing on profitability.



Petro-Canada has interests in the next two likely developments on the Grand Banks, White Rose (our share is 17.5 per cent) and Hebron/Ben Nevis (our share is 23.9 per cent). Both fields saw promising drilling results in 1999. Current timelines suggest that White Rose could come on stream in 2004, with Hebron/Ben Nevis following in 2005. A minimum of four exploration or delineation wells are planned for 2000, including potential locations at White Rose, Hebron, Riverhead and Southwest Hibernia.

While we are beginning to see the positive earnings impact of current Grand Banks projects, we are also accelerating long-term exploration in the offshore. We have a strong land position in the Flemish Pass basin, including the acquisition in November 1999 of approximately 653 000 net acres, bringing our total holdings in this basin to approximately 738 000 net acres. Seismic work on the Flemish Pass acreage will begin in 2000, in Petro-Canada's first foray into Grand Banks exploration beyond the Jeanne d'Arc basin. The Flemish Pass would be a deepwater development, made possible by global advances over the last decade in deepwater drilling and development technology.

Expanding Oil Sands Production

Petro-Canada sees significant growth potential from the immense reserves of the oil sands in northern Alberta. In the near term, we are engaged in the major expansion underway at Syncrude, which includes several stages of mine and upgrading expansions. Our share of Syncrude production is expected to increase to approximately 30 000 barrels per day in 2000, 44 000 barrels per day in 2004, and over 50 000 barrels per day by 2007. At the same time, operating costs are expected to decrease, falling to approximately $11 per barrel by 2008.

Ownership of major *in situ* oil sands leases gives Petro-Canada the potential for further production growth from oil sands in the future. We are evaluating development options for this resource, beginning with a 22 000 barrel per day production facility at MacKay River. *In situ* oil sands are too deep to be mined from the surface as they are at Syncrude. The bitumen must therefore be extracted "in place," in this case by drilling pairs of wells and injecting steam — a process known as SAGD, or Steam-Assisted Gravity Drainage.

Exploring New Gas Opportunities

In order to build long-term growth opportunities, Petro-Canada has acquired a 60 per cent position in two attractive land parcels in the Mackenzie Delta region of the Northwest Territories, totaling approximately 220 000 net acres. The large gas deposits in this region are well established; the Geological Survey of Canada estimates the potential of the Mackenzie Delta to be in the range of 20 trillion cubic feet of natural gas, including the six trillion cubic feet already discovered. We are moving quickly to follow up on this land acquisition. We will undertake a large seismic program on the properties during the winters of 1999/2000 and 2000/2001. Development of Mackenzie Delta gas would require confirmation of large reserves and strong gas prices to support a major new pipeline.

In 1999, Petro-Canada also acquired 147 000 net acres on the deepwater Scotian Shelf offshore Nova Scotia, an area that is highly prospective for natural gas. As well, we entered into a farm-in agreement on an adjoining block of 495 000 net acres. We will acquire some 2 000 square kilometres of three-dimensional seismic on the Scotian Shelf parcels in 2000 to evaluate this acreage.

Gulf Canada refining and marketing operations in Ontario and the West come into the fold, rounding out a national network strong in every region.

Downstream Sector Review

Overview of Operations

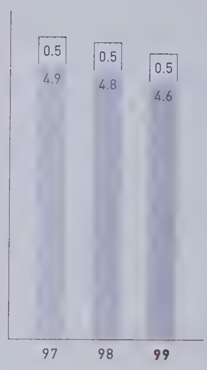
Petro-Canada is one of Canada's strongest retail brands in refined petroleum products. Refining and marketing is a core business for us. Our Downstream operations consist of refineries in Edmonton, Oakville and Montreal, a lubricants manufacturing plant in Mississauga, and a network of retail and wholesale outlets nationwide.

The goal of the Downstream is to achieve financial returns consistently greater than the cost of capital invested in the business. Because the business environment can be extremely challenging, as it was in 1999, it is essential to deliver on key controllable operating measures such as non-petroleum revenue, retail volume per site, product mix and refinery performance. Petro-Canada has streamlined its Downstream business to produce strong competitive performance on these measures.

The strength of Petro-Canada's Downstream is its integration of efficient refining operations with a superb retail and wholesale brand offering, focusing on select regional market segments, according to the characteristics of each refinery.

DOWNSTREAM OPERATING AND OVERHEAD COSTS

Per-litre costs continued to decline.



Unit operating costs *(cents per litre)*

☐ Unit overhead costs *(cents per litre)*

Downstream Sector 1999 Results

Financial Results (millions of dollars, unless otherwise indicated)

	1999	1998	1997
Earnings from operations	**115**	204	225
Losses on sale of assets	**(9)**	(35)	(6)
Net earnings	**106**	169	219
Cash flow	**163**	420	415
Operating return on capital employed (per cent)	**5.7**	10.3	11.4
Average capital employed	**2 020**	1 981	1 970

1999 Compared with 1998

Downstream earnings and cash flow declined significantly in 1999, following two years of strong results, as a direct consequence of the most difficult industry environment in several years. In Petro-Canada's case, rising crude oil prices, low refining margins, and narrow price differentials between grades of crude oil all played a role, and tended to reinforce one another.

The price of crude oil more than doubled during 1999, the most remarkable increase in more than a decade. This rapid rise in feedstock costs was only partially recovered by corresponding increases in product prices. The resulting squeeze in product margins had a major impact on Petro-Canada's earnings. In 1999 we also saw very low refining margins — the margin between the cost of crude oil and the wholesale price received for refined products such as gasoline.

Another factor affecting our Downstream earnings was the unusually narrow spread between the price of light crude oil and that of heavy crude oil. Our refineries have the flexibility to operate on heavier grades of oil than others do, which normally means lower feedstock costs. In 1999, narrow light/heavy differentials reduced this competitive advantage.

Petro-Canada organizes and sponsors the 88-day Olympic Torch Relay — carrying the Olympic flame through every province and territory on the way to the Calgary Winter Olympics — inspiring Canadians and marking a turning point in their acceptance of the Petro-Canada brand.

The financial impact of the poor Downstream business environment was partially offset by strong performance on controllable operating factors. One such factor, reflecting performance in both the refining and marketing businesses, is total sales volumes. Petro-Canada sold 51 200 cubic metres per day of refined petroleum products in 1999, up from 49 100 cubic metres per day in 1998, and continuing a steady upward trend. While overall demand for refined petroleum products in Canada increased by only 1.3 per cent in 1999, Petro-Canada's total volumes sold increased by 4.4 per cent. At the same time, we reduced our Downstream unit operating and overhead costs to 5.1 cents per litre, down from 5.3 cents in 1998.

Marketing

Petro-Canada's retail and wholesale marketing operations showed strong performance on a competitive basis in 1999, despite the negative impact of the business environment on total earnings. Operating earnings in the marketing segment were $81 million in 1999, compared with $84 million in 1998.

Along with higher total sales volumes, the average annual volume sold per retail site (known as the retail throughput) also showed a solid increase, to 3.6 million litres per site from 3.5 in 1998. Petro-Canada's retail throughputs are the highest among the national integrated companies. We tightly managed expenses, and reduced overall costs per litre sold.

Petro-Canada also increased its contribution from non-petroleum products and services by 12 per cent in 1999. The higher non-petroleum contribution is a particularly important component of profitability, mitigating the impact of fluctuating profit margins on gasoline. In 1999, Petro-Canada convenience stores achieved significant sales growth as we expanded our network and launched new offerings such as JavaStop coffee and CoolStop Avalanche slush products. Car wash sales also increased substantially as we continue to improve wash quality, automation and convenience.

Petro-Canada's retail network consisted of 1 658 sites at year end, of which 885 are company-controlled, while the others are owned by third parties. Redevelopment of the retail network to our new-image sites continued, building on a successful formula that has now been proven in markets across the country. By the end of 1999, we had converted 29 per cent of our company-controlled outlets to the new design. The new-image sites continue to demonstrate strong increases in gasoline sales, achieving average annual throughputs of 6.8 million litres.

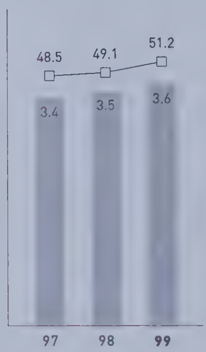
Petro-Canada enjoys outstanding brand recognition as *Canada's Gas Station*. This brand strength was reinforced with an award-winning advertising campaign on our trademark WinterGas, which emphasized Petro-Canada's focus on products designed for Canadian driving conditions. In May 1999, we introduced our new clean gasolines, containing TACTROL, our proprietary deposit control additive.

Petro-Points, our customer loyalty program, continues to be one of the strongest programs of its kind. We expanded the program in 1999, providing enhanced automotive and convenience offerings for points redemption. In addition, we introduced the Petro-Points Auto Club, a vehicle-based program offering emergency assistance and travel planning. Petro-Points also welcomed a new partner, North American Van Lines Canada. At the end of 1999, approximately 4.3 million Canadian households were members of Petro-Points.

At the wholesale level, we continue to build on our strong position in the commercial road transport market through our Petro-Pass cardlock network. Petro-Pass sales increased by 12 per cent in 1999, as we expanded our national cardlock network to 196 sites. To improve customer service, we introduced an Internet-based application that enables fleet customers to access timely transaction and pricing data.

KEY SALES FIGURES

The Downstream again increased total sales and sales per retail site.



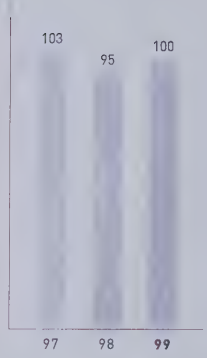
Retail throughputs per site *(millions of litres per year)*

☐ Petroleum product sales *(thousands of cubic metres per day)*

The federal government announces in February that it will privatize Petro-Canada; legislation is introduced in October.

REFINERY UTILIZATION

Refineries ran at full capacity in 1999.



Crude capacity utilization
(per cent)

- Our rated refinery crude capacity was increased in 1998, following process improvements. The 1997 figure is based on the lower rated capacity.

Refining and Supply

Petro-Canada's refining business improved on key operating measures in 1999, but the extremely poor business environment had a negative impact on earnings. Earnings in refining and supply were $34 million in 1999, down from $120 million in 1998.

Utilization of refinery crude capacity, a key measure of efficiency, increased to 100 per cent in 1999, up from 95 per cent in 1998. This excellent utilization rate follows a 1998 increase of eight per cent in Petro-Canada's rated refinery capacity to approximately 49 000 cubic metres, or 308 000 barrels per day. In asphalt production, we matched our sales record of 1.4 billion litres. As well, our refineries showed continued improvement in the Energy Intensity Index, an industry-wide measure of energy efficiency.

The Oakville refinery gained access to an increased selection of feedstocks in 1999, due to the reversal of Enbridge Inc.'s Line 9 pipeline, which enables the supply of offshore light crude oil through Montreal. Petro-Canada refineries also achieved compliance with the new regulatory standard for reduced benzene levels in gasoline.

Lubricants

Petro-Canada's Lubricants business unit was repositioned in 1999, with a new management team and a strategy for improved financial performance. The strategy centres on improving margins by optimizing the product mix, thereby capturing the Mississauga plant's competitive advantage in producing high-value specialized products.

Results of the new approach included an eight per cent increase in total sales volumes. The product mix also improved, with a shift in sales volumes toward higher-margin products such as white oils. However, 1999 earnings suffered from the sharp increase in crude oil prices, which increased feedstock costs, and the impact of a fire at the lubricants facility in January.

Downstream Outlook

Retail Brand of Choice

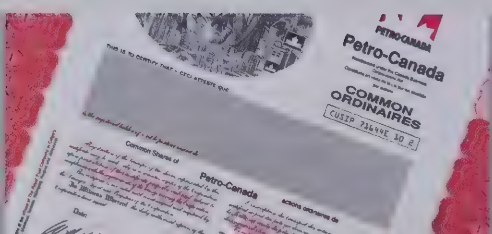
Petro-Canada's key levers for retail success include our compelling product and service offering, competitive pricing, leading-edge facilities, and strong customer relationships. The efforts of the last few years have positioned our brand for competitive success in the retail and wholesale markets.

We will continue to pursue our successful formula for retail site redevelopment on a market-by-market basis in 2000, as we position Petro-Canada as the brand of choice across Canada. Our retail redevelopment program is critical to expanding non-petroleum contribution and to maintaining earnings despite the cyclical business environment.

On the wholesale side, we will continue focusing on the important commercial road transport market. We will pursue measured growth in our Petro-Pass cardlock network, while improving our ancillary products and services to provide a fuller offering that meets the needs of the trucking market.

In 2000, we will explore opportunities to enhance and expand applications of e-commerce technology.

Privatization legislation passes and, on July 3, the first Petro-Canada shares are sold to the public.



Meeting Regulatory Challenges in Refining

A key challenge over the medium term will be meeting the Canadian government's new regulation limiting allowable levels of sulphur in gasoline. The current regulation requires sulphur to be reduced to an average of 150 parts per million between mid-2002 and the end of 2004, with a further reduction to 30 parts per million by 2005. Petro-Canada supports the government's efforts to improve air quality. Our current capital estimates for refinery upgrades to achieve 30 parts per million are in the range of $350 to $450 million. However, meeting the interim step of 150 parts per million presents a further financial challenge. We continue to evaluate potential technology and operating solutions to meet the environmental regulation while minimizing supply disruptions and the required capital expenditure.

Petro-Canada's refining group will continue to strive for safe and reliable operations, improved performance on all operating measures, and increased market share in select niche markets.

Improving Performance in Lubricants

Priorities for 2000 in Lubricants will include further increases in sales of high-value niche products such as white oils and very high viscosity index liquids, as well as continuing progress on process improvements, pricing and plant reliability. No major capital expenditures are required to meet pending environmental regulations.

Shared Services Results

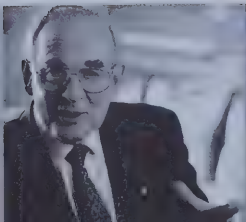
Financial Results (millions of dollars)

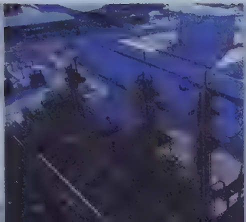
	1999	1998	1997
Net expenses before reorganization costs	**(122)**	(103)	(99)
Gains on sale of assets	**—**	12	—
Net expenses	**(122)**	(91)	(99)
Cash flow before reorganization costs	**(84)**	(68)	(52)

1999 Compared with 1998

Shared Services is structured as a cost centre that includes interest expense, general corporate revenues and expenditures, and investment income. Net expenses from Shared Services increased in 1999, due largely to interest costs that rose by $19 million. The higher interest costs are a result of reduced interest capitalization on the Hibernia project.

Jim Stanford is appointed President and CEO.
Refining network reconfigured to eliminate excess capacity.





LIQUIDITY AND CAPITAL RESOURCES

Summary of Cash Flows (millions of dollars)

	1999	1998	1997
Operating Activities			
Cash flow	**964**	830	1 263
(Increase) decrease in operating working capital and other	**(155)**	238	(167)
Cash flow from operating activities	**809**	1 068	1 096
Investing activities	**(945)**	(628)	(863)
Financing activities and dividends	**(89)**	(84)	(190)
(Decrease) increase in cash and short-term investments	**(225)**	356	43

Operating Activities

Cash flow increased by 16 per cent in 1999, reflecting higher earnings that were partially offset by higher current taxes. In the Downstream, the inventory accounting method required for tax purposes resulted in an increase in current income taxes of $141 million in 1999, compared with a decrease in taxes of $66 million in 1998, for a total negative year over year impact on cash flow of $207 million. In the Upstream, the structure of the Petro-Canada Oil and Gas Partnership caused current taxes to decrease by $100 million in 1999, compared with an increase of $75 million in 1998, for a total positive year over year impact of $175 million.

Investing Activities

Capital and Exploration Expenditures (millions of dollars)

	1999	1998	1997
Upstream [1]			
Western Canada oil and gas exploration and development	**276**	361	321
Hibernia and Terra Nova	**283**	225	182
Other Grand Banks	**42**	20	23
International	**47**	72	70
Syncrude and other oil sands	**107**	70	52
Property acquisitions	**22**	43	112
Other	**16**	27	45
	793	818	805
Downstream			
Refining and supply	**110**	125	75
Marketing	**90**	133	116
Lubricants	**20**	15	20
Other	**—**	3	4
	220	276	215
Shared Services	**8**	22	29
Total property, plant and equipment and exploration	**1 021**	1 116	1 049
Deferred charges and other assets	**5**	17	15
Total	**1 026**	1 133	1 064

1 Includes exploration expenses charged to earnings of $78 million in 1999, $95 million in 1998 and $75 million in 1997.

Petro-Canada's first well in Algeria, in the Tamadanet field, yields attractive oil discovery. Retail network rationalization boosts efficiency. Lubricants expansion announced.


1999 Compared with 1998

Petro-Canada's capital expenditures were $1 026 million in 1999, down nine per cent from 1998. Expenditures declined in both the Downstream and in Western Canada exploration and development, more than offsetting increases in Grand Banks and oil sands investments.

In the Upstream, the largest share of Grand Banks spending, $241 million, went to the Terra Nova development under construction. Hibernia expenditures decreased by $21 million, while other Grand Banks investment, focused on identifying future opportunities, increased to $42 million from $20 million in 1998. As the Syncrude expansion plan progressed, spending on oil sands increased by $37 million in 1999. On the other hand, capital spending in the Western Canada conventional business dropped by 24 per cent, and expenditures also decreased for international activities and property acquisitions.

The Downstream saw a significant decline in capital expenditures in 1999, to $220 million from $276 million a year earlier. This decline reflected the conclusion of some 1998 capital investments at Petro-Canada refineries, most notably equipment to reduce the benzene content in gasoline, and a catalytic cracker expansion in Montreal. Investments on the marketing side were also lower, as we consolidated gains in the retail and wholesale network while pursuing the phased roll-out of new-image retail sites.

In 1999, Petro-Canada sold interests in several small oil fields for a total cash consideration of $54 million. We also invested $22 million to acquire interests in our core natural gas properties.

2000 Capital Budget

Reflecting the strength of Petro-Canada's balance sheet and the value to be realized from our core assets, we will increase capital expenditures to approximately $1 200 million for 2000, up 17 per cent from 1999. We intend to fund this capital program from internal sources.

Investment in the Western Canada conventional business, mainly natural gas, will increase significantly to $395 million in 2000. Grand Banks expenditures will remain substantial at $310 million, including steady-state spending at Hibernia of almost $40 million, $190 million at Terra Nova, and $80 million on potential future developments, including significant capital for exploration. We plan to spend $145 million on Syncrude and other oil sands properties, as we fund the Syncrude expansion and evaluate our *in situ* oil sands resources. International expenditures are planned to increase to $105 million.

In the Downstream, capital investment will remain steady at $220 million. This level of spending will enable the continuation of our successful retail program and the maintenance of high efficiency and utilization levels at Petro-Canada refineries.

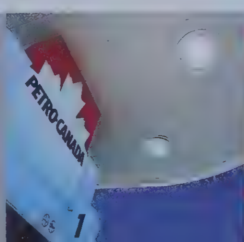
Drive for Profitability

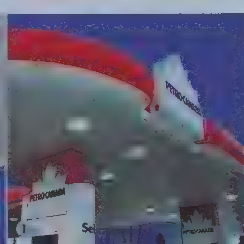
Delivering on Petro-Canada's potential requires a disciplined effort to improve performance and a focused approach to ensure profitability. We are currently examining all of our assets to ensure they are individually contributing to bottom-line results. As a consequence, we may expand, reduce, or change our portfolio of businesses in the future. Possibilities include the sale of certain non-core assets beyond the Western Canada oil properties and natural gas liquids business discussed on page 32, together with organizational changes. No decisions have been taken at this time. These initiatives could result in a charge to earnings in 2000, which may be material.

Accounting Changes

The Canadian Institute of Chartered Accountants has issued new standards on accounting for employee future benefits, including pensions, and on accounting for income taxes. These standards, effective on January 1, 2000, were adopted by Petro-Canada in the first quarter of 2000. The changes reduce shareholders' equity and may introduce more volatility into annual results, although income statement effects are not expected to be material.

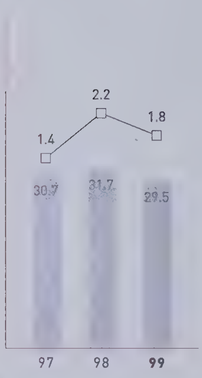
The Government of Canada sells shares amounting to 50 per cent of Petro-Canada's common stock, reducing its interest to 20 per cent. Growing investor confidence brings significant appreciation in the Company's market value. Petro-Canada unveils its first new-image retail sites.





KEY DEBT RATIOS

The balance sheet remains strong, with conservative debt ratios.

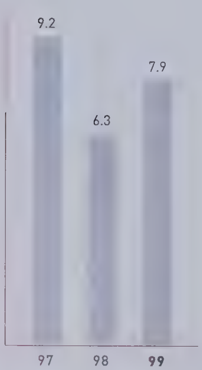


Debt to debt plus equity *(per cent)*

☐ Debt to cash flow *(times)*

INTEREST COVERAGE

A positive interest coverage ratio demonstrates more than sufficient earnings to cover interest charges on debt.



Interest coverage ratio *(times)*

- Calculated on an EBITDAX basis.

Financing Activities and Dividends

Sources of Capital Employed (millions of dollars)

	1999	1998	1997
Long-term debt, including current portion	**1 711**	1 829	1 491
Notes payable — Hibernia	**—**	—	250
Shareholders' equity	**4 083**	3 936	3 922
	5 794	5 765	5 663
Foreign currency translation adjustment on long-term debt[1]	**(87)**	(212)	(145)
Total	**5 707**	5 553	5 518

1 The translation adjustment on long-term debt is amortized over the remaining term of the debt. The weighted average term of the debt was 19 years at December 31, 1999.

Petro-Canada has established leverage targets to ensure continued balance sheet strength and financial flexibility. These targets include a debt to cash flow ratio of 2.0 times and debt to debt plus equity of 30 per cent.

Total debt decreased by $118 million, due primarily to the effect of the stronger Canadian dollar exchange rate relative to the U.S. dollar on debt denominated in U.S. dollars. The fiscal regime for the Hibernia offshore oil field gave Petro-Canada access to a total of $250 million in Government of Canada guaranteed debt. In 1999, we voluntarily relinquished our entitlement to this debt facility.

In October, Petro-Canada increased its quarterly dividend from $0.08 to $0.10 per common and variable voting share, which increased dividends declared to $92 million in 1999, from $87 million in 1998.

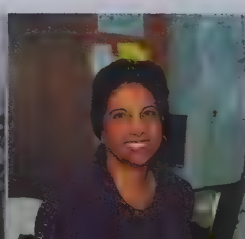
Petro-Canada will continue to meet working capital and bridge financing requirements using our cash position and through the issuance of short-term debt if necessary. For operating purposes, Petro-Canada has access to bank lines of credit and a commercial paper program totaling $1 175 million, supported by committed and demand credit facilities from several major Canadian financial institutions. As of December 31, 1999, the commercial paper program was not utilized as our net cash and short-term investments were $206 million. In the latter part of 1999, we cancelled a syndicated bank line of credit in the amount of $1 125 million that was entered into in early 1999 for general corporate and acquisition purposes.

Moody's Investor Service's credit rating on Petro-Canada's unsecured long-term debt is A3 and Standard & Poor's is BBB+. Dominion Bond Rating Service and the Canadian Bond Rating Service ratings on Petro-Canada's unsecured long-term notes and debentures are both A.

Financial Ratios

	1999	1998	1997
Current ratio	**1.2**	1.4	1.3
Interest coverage (times)			
— earnings basis	**3.7**	2.2	5.3
— EBITDAX basis	**7.9**	6.3	9.2
— cash flow basis	**8.2**	6.7	9.4
Debt to cash flow (times)	**1.8**	2.2	1.4
Debt to debt plus equity (per cent)	**29.5**	31.7	30.7

Petro-Canada acquires Amerada Hess Canada, adding production and exploration opportunities in Western Canada. Alliance formed with Norsk Hydro, bringing interests in production off Norway and access to offshore expertise.



RISK MANAGEMENT

Management oversees the overall direction, conduct and control of the Company's risk management activities, according to the mandate, policies and guidelines established by the Board. Hedging, insurance, and other techniques are used.

Our risk management policy prohibits the use of derivative instruments for speculative purposes. Petro-Canada uses derivatives only to hedge its physical volumes. Except as specifically authorized by the Board of Directors, the term of hedging instruments cannot exceed 18 months. We transact derivatives with counterparties who possess a minimum long-term credit rating of A (unless otherwise approved by the Board of Directors) under a signed International Swap Dealers Association agreement. Credit limits take into account current and potential exposure to losses due to non-performance of a counterparty and reduce credit risk concentration with any single counterparty. Monitoring and reporting of the derivatives portfolio includes periodic testing of the fair value of all outstanding derivatives.

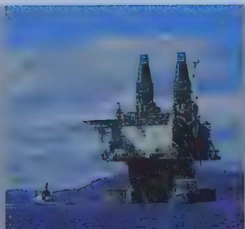
Petro-Canada has used derivatives to hedge its exposure to changes in commodity prices, currency exchange rates, and interest rates. The net effect of commodity, currency and interest rate hedging during 1999 reduced earnings by approximately $33 million after tax.

As of December 31, 1999, Petro-Canada had sold forward approximately 21 000 barrels per day of crude oil production for the first quarter of 2000 at U.S. $22.55 per barrel. We sold forward approximately 106 million cubic feet of daily natural gas production at a minimum average price of $2.96 per thousand cubic feet Alberta and British Columbia plant gate equivalent. Basis swaps were in place to diversify the portfolio's physical price risk and manage transportation exposure. A small percentage of heating oil margin for calendar 2000 has been sold forward and crude oil contracts have been bought forward to mitigate margin exposure for fixed-price product sales. Short-term hedge positions were also in place for refining supply and product purchases.

In the future, derivatives will be used primarily to hedge physical transactions for operational needs and to facilitate sales to customers and financial transactions. Commodity prices and margins may be hedged occasionally to capture opportunities that represent extraordinary value.

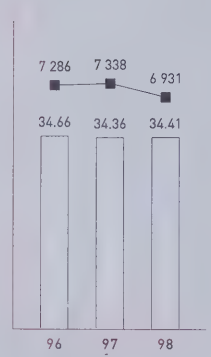
We manage operational risk through comprehensive risk assessment and loss management processes, and maintain adequate insurance coverage. Petro-Canada places insurance coverage globally, with financially secure insurers. Limits of insurance are based on engineering risk assessments and deductibles are set at levels that reflect our ability to retain the risk.

Hibernia production platform towed to site; first two wells deliver initial production of 60 000 barrels per day. Eight consecutive gas discoveries highlight revival of once-dormant Wildcat Hills field



GREENHOUSE GAS EMISSIONS VERSUS PRODUCTION

Investments in energy efficiency have reduced total greenhouse gas emissions.



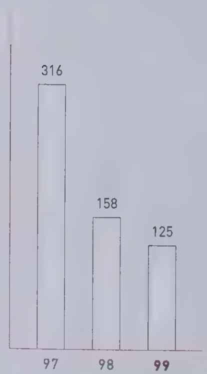
☐ Total Upstream and Downstream production *(million cubic metres oil equivalent/year)*

■ GHG emissions *(kilotonnes/year)*

- 1999 data is not yet available.

UPSTREAM PERMIT EXCEEDANCES

The Upstream has significantly reduced emissions over permit limits.



☐ Number of permit exceedances

CORPORATE RESPONSIBILITY

Petro-Canada regards high standards of corporate responsibility as sound business practice. Responsible environmental stewardship reduces costs, a safe and healthy workplace increases productivity, and investing in the communities where we operate builds support for our activities. Our Code of Business Conduct, approved by the Board of Directors, guides the standards of behavior and ethics that are expected in all Petro-Canada business operations.

Safeguarding the Environment

As a natural resource company, we recognize that sound environmental practices are fundamental to doing business. We spent approximately $145 million on environmental programs in 1999, of which $70 million was capital expenditures on facility upgrades, and $75 million was operating expenses. We anticipate that the costs of meeting environmental challenges will increase over time, as the oil and gas industry faces increasing public and regulatory scrutiny relating to protection of the environment. Petro-Canada's environmental management is organized through the Total Loss Management framework, under which each business unit undergoes a major internal audit every four years. We conducted five such audits in 1999.

We incorporate environmental considerations into all stages of project planning and implementation, assessing potential impacts over the life of a project. Life Cycle Value Assessment enables us to reduce environmental impacts from the outset, rather than face costly mitigation later.

In 1999, Petro-Canada placed particular emphasis on reducing sulphur emissions, reducing greenhouse gas emissions through improved energy efficiency, reducing total environmental permit exceedances in our Upstream operations, and reducing total effluent emissions in the Downstream.

Cutting Sulphur Emissions

Sulphur occurs naturally in crude oil and raw natural gas. It is removed through processes in refineries and gas plants, and recovered sulphur is sold as a commodity on international markets. Sulphur is an air pollutant when it is emitted in the form of sulphur dioxide or hydrogen sulphide.

Petro-Canada has achieved considerable success in reducing sulphur emissions in both our Upstream and Downstream businesses. In 1999, we reduced total emissions by 11 per cent, to 31 900 tonnes from 35 900 in 1998, largely by using lower-sulphur crude feedstock at our refineries.

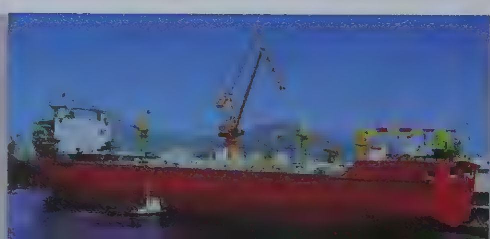
Petro-Canada's Downstream is addressing the need to meet reduced sulphur limits in gasoline (see page 39). However, reducing sulphur in gasoline raises other environmental issues, as more energy must be used in refining to eliminate sulphur. Lower sulphur levels can therefore result in higher greenhouse gas emissions. Petro-Canada is evaluating new technology that has the potential to meet the new, stringent standard for sulphur in gasoline, while maximizing energy efficiency.

Making Progress on Greenhouse Gas Emissions

Another environmental priority for Petro-Canada is minimizing emissions of greenhouse gases, primarily carbon dioxide and methane, which have been linked to global climate change. Petro-Canada supports Canada's Voluntary Challenge and Registry, and we received a Leadership Award from the program in 1999 for our achievements in measuring and reducing our greenhouse gas emissions.

Petro-Canada has significantly reduced annual greenhouse gas emissions per unit of production. In 1998 alone, we cut more than 70,000 tonnes from our annual emissions, largely through an eight per cent improvement in energy efficiency in the Upstream, and a two per cent improvement in the Downstream. Petro-Canada's total greenhouse gas emissions for 1998 were within one per cent of their 1990 level, even though production increased over that period by 29 per cent.

Terra Nova offshore oil development launched following regulatory and owner approval. Record natural gas reserve additions.



Exploring Alternative Fuel Opportunities

Environmental concerns may lead to growing market demand for low-emission fuels. Fuel cells are a promising, environmentally attractive technology. Petro-Canada is keeping abreast of developments in this field, and we intend to participate in eventual fuel distribution to Canadians regardless of the type of fuel employed. As a preliminary step, in June 1999, Petro-Canada announced a memorandum of understanding with Ballard Power Systems Inc. and Methanex Corporation, under which the three companies will collaborate in a demonstration pilot project involving the supply and distribution of appropriate fuel for fuel cell vehicles.

Also in 1999, construction began on a small-scale plant to demonstrate the commercial viability of a leading-edge technology, pioneered by Iogen Corporation, to produce fuel ethanol from biomass. This Canadian technology uses enzymes to break down cellulose found in by-products from forestry and agriculture. The process has the potential to reduce related greenhouse gas emissions by more than 90 per cent compared with the production and use of gasoline. Petro-Canada committed to fund the research and development phase of this promising technology, to demonstrate the commercial viability and allow eventual independent financing of a full-scale plant.

Improvement on Key Measures in the Upstream and Downstream

Petro-Canada generally operates well within all permitted limits for emissions of pollutants, but these limits are occasionally exceeded, usually for very brief periods. Exceedances occur when emissions temporarily rise above the levels specified in a facility's operating permit, typically in the event of a plant process upset. In the Upstream, permit exceedances are a key measure of environmental performance. We have reduced exceedances significantly — by 50 per cent in 1998 and by a further 21 per cent in 1999. We strive to operate within all permits at all times.

In the Downstream, federal legislation requires measurement and reporting of five "conventional pollutants" from our refining operations. In 1999, Petro-Canada reduced total emissions of these effluents from our refineries and lubricants plant by 25 per cent. This improvement was the result of better process controls and treatment, as well as improved testing methods and analysis.

Creating a Healthy Work Environment

Petro-Canada endeavours to ensure the safety and well-being of all our employees, from machinery operators to office staff. Our key measure in this regard is the Employee Recordable Injury Frequency, which declined by almost 30 per cent in 1999, to 1.01 injuries per 200 000 person-hours from 1.42 in 1998. There were 47 injuries in total in 1999, and their severity, measured by lost time, decreased by almost 45 per cent from 1998. We are striving for further reductions, as a new integrated reporting system will provide better analysis of the causes of injuries, enabling better prevention.

While recordable injuries are highly visible workplace safety indicators, we are also addressing broader employee health and wellness issues. Ergonomic assessments continued in 1999, as did various employee wellness and fitness initiatives.

REFINERY EFFLUENT EMISSIONS

Our refineries sharply reduced the discharge of pollutants in 1999.

☐ Five pollutant total *(tonnes)*

– Includes five "conventional pollutants" as defined by Environment Canada. The pollutants are phenolics, oil and grease, sulphides, suspended solids, and ammonia.

Hibernia reaches production of 150 000 barrels per day at year end. Exploration continues to identify next Grand Banks development. Land acquisitions target new natural gas areas, Mackenzie Delta and offshore Nova Scotia.

Working Toward our Social Vision through Community Investment

Petro-Canada is working to achieve the social vision it launched in 1998, by focusing on the development of Canadian talent, innovation and expertise through education. Petro-Canada is investing in Canada's future by funding a wide range of educational programs for young people, including several environmental initiatives. Petro-Canada also supports many non-profit organizations that deliver much-needed health and social services to our communities, addressing issues like poverty, child hunger, homelessness, and family violence.

In 1999, Petro-Canada invested $5.0 million in 325 non-profit organizations across Canada in education, environment, health and community services, and arts and culture. As an Imagine Caring Company (a program of the Canadian Centre for Philanthropy), we target to invest one per cent of pre-tax earnings in charitable endeavours.

Petro-Canada employees again demonstrated their personal commitment to community investment in 1999, as illustrated by the record-breaking contribution of $1.2 million to the United Way/Centraide. This combined corporate and employee contribution increased by $102 000 over 1998. As well, Petro-Canada matched employee donations to Red Cross relief efforts around the world, for a total contribution of $140 000.

To encourage and support employee volunteerism, Petro-Canada provided 287 grants in 1999 to employee and retiree volunteers, with contributions of $300 each to non-profit organizations across the country where Petro-Canada's people are making a difference.

Community investments in 1999 included:

Petro-Canada Young Innovator Awards to six young faculty researchers at universities, colleges and institutes across Canada. Since 1994, we have invested nearly $4 million in this flagship research and education program.

$520 000 in scholarships from the Petro-Canada Olympic Torch Scholarship Fund, enabling 139 Canadian athletes and coaches to pursue their education while training for competition.

Scholarships totaling $60 000 to 27 students through the National Aboriginal Achievement Foundation. Since 1985, the company has invested more than $570 000 to assist native students completing degrees related to the oil and gas industry.

Funding to 28 post-secondary institutes, ranging from Northern Lights College in Fort St. John to Memorial University in St. John's. At Memorial and the University of Calgary, Petro-Canada sponsors chairs for Women in Science and Engineering.

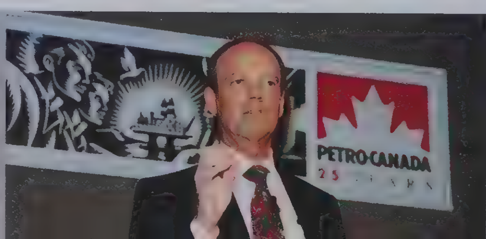
Initiatives launched in 1999 include:

The Edmonton Zoo School, where young students integrate aspects of their curriculum into a week-long field study of animals and their environment.

The Royal Conservatory of Music's Learning Through the Arts Program, bringing artists into the classroom to help teachers deliver core curriculum using music, story-telling, puppetry, dance, drama and visual arts activities as learning tools.

The Conservation Corps of Newfoundland and Labrador's Climate Change Action Program, encouraging energy conservation through household environmental audits.

Three large natural gas discoveries in the Wildcat Hills area usher in the new year. Ron Brenneman is appointed President and CEO. Employees celebrate Petro-Canada's 25th anniversary.



MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

The preparation and presentation of the Company's consolidated financial statements is the responsibility of management. The financial statements have been prepared in accordance with generally accepted accounting principles and necessarily include estimates which are based on management's best judgments. Information contained elsewhere in the Annual Report is consistent, where applicable, with that contained in the financial statements.

Management is also responsible for installing and maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that reliable financial information is produced for preparation of financial statements.

Arthur Andersen LLP, a firm of chartered accountants, were appointed by the shareholders as external auditors to conduct an independent examination and express their opinion on the consolidated financial statements. The Auditors' Report outlines the auditors' opinion and the scope of their examination. The Company has also contracted Arthur Andersen LLP to provide other audit services, including a review of the system of internal controls to ensure that there are no significant weaknesses.

The Board of Directors is responsible for overseeing management's performance of its responsibilities for financial reporting and internal control. The Board exercises these responsibilities with the assistance of the Audit Committee of the Board.

R.A. Brenneman

Ronald A. Brenneman
President and Chief Executive Officer

E.F.H. Roberts

Ernest F.H. Roberts
Senior Vice-President and
Chief Financial Officer

January 27, 2000

AUDIT COMMITTEE OF THE BOARD OF DIRECTORS

The Board of Directors exercises its responsibility for overseeing management's performance of its financial reporting and internal control responsibilities with the assistance of the Audit Committee of the Board.

The Committee, which is composed of not less than three (currently five) directors who are not employees of the Company, reviews the annual consolidated financial statements prior to their approval by the Board. The Committee also reviews financial information contained in prospectuses and in reports filed with regulatory authorities, as required, as well as quarterly financial information.

With respect to the external auditors, the Committee reviews the terms of engagement, the annual audit plan, the Auditors' Report and the results of the audit. The Committee also recommends to the Board a firm of external auditors to be appointed by the shareholders.

With respect to Arthur Andersen LLP's engagement as contract auditor to review the system of internal controls, the Committee receives periodic reports, reviews significant findings and recommendations and approves their engagement contract and annual review plan, which is based on an assessment of risks.

Senior management, the external auditor and the contract auditor attend all Audit Committee meetings and each is provided with the opportunity to meet privately with the Committee.

Claude Fontaine

Claude Fontaine
Chairman of the Audit Committee

January 27, 2000

AUDITORS' REPORT

To the Shareholders of Petro-Canada:

We have audited the consolidated balance sheet of Petro-Canada as at December 31, 1999 and 1998 and the consolidated statements of earnings, retained earnings and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1999 and 1998 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1999 in accordance with generally accepted accounting principles.

Arthur Andersen LLP

Arthur Andersen LLP
Chartered Accountants
Calgary, Alberta

January 27, 2000

Consolidated Statement of Earnings

(stated in millions of Canadian dollars)

For the years ended December 31,	1999	1998	1997
REVENUE			
Operating	$ 6 095	$ 4 951	$ 6 017
Investment and other income	52	65	79
	6 147	5 016	6 096
EXPENSES			
Crude oil and product purchases	3 436	2 413	3 183
Producing, refining and marketing	1 236	1 309	1 352
General and administrative (Note 4)	221	265	194
Exploration	78	95	75
Depreciation, depletion and amortization	558	530	482
Taxes other than income taxes	55	63	68
Interest	141	122	106
	5 725	4 797	5 460
EARNINGS BEFORE INCOME TAXES	422	219	636
PROVISION FOR INCOME TAXES (Note 5)			
Current	147	166	(41)
Deferred	42	(42)	371
	189	124	330
NET EARNINGS	$ 233	$ 95	$ 306
EARNINGS PER SHARE (dollars) (Note 6)	$ 0.86	$ 0.35	$ 1.13

Consolidated Statement of Retained Earnings

(stated in millions of Canadian dollars)

For the years ended December 31,	1999	1998	1997
RETAINED EARNINGS (DEFICIT) AT BEGINNING OF YEAR	$ 147	$ 139	$ (88)
Net earnings	233	95	306
Dividends on common and variable voting shares	(92)	(87)	(79)
RETAINED EARNINGS AT END OF YEAR	$ 288	$ 147	$ 139

Consolidated Statement of Cash Flows

(stated in millions of Canadian dollars)

For the years ended December 31,	**1999**	1998	1997
OPERATING ACTIVITIES			
Net earnings	**$ 233**	$ 95	$ 306
Items not affecting cash flow (Note 7)	**653**	640	882
Exploration expenses (Note 12)	**78**	95	75
Cash flow	**964**	830	1 263
(Increase) decrease in operating working capital and other (Note 8)	**(155)**	238	(167)
Cash flow from operating activities	**809**	1 068	1 096
INVESTING ACTIVITIES			
Expenditures on property, plant and equipment and exploration	**(1 021)**	(1 116)	(1 049)
Proceeds from sales of assets (Note 9)	**81**	505	201
Increase in deferred charges and other assets, net	**(5)**	(17)	(15)
	(945)	(628)	(863)
FINANCING ACTIVITIES AND DIVIDENDS			
Dividends on common and variable voting shares	**(92)**	(87)	(79)
Reduction of long-term debt	**(3)**	(140)	(114)
Proceeds from issue of common and variable voting shares	**6**	6	3
Proceeds from issue of long-term debt	**—**	387	—
Reduction of notes payable — Hibernia	**—**	(250)	—
	(89)	(84)	(190)
(DECREASE) INCREASE IN CASH AND SHORT-TERM INVESTMENTS	**(225)**	356	43
CASH AND SHORT-TERM INVESTMENTS AT BEGINNING OF YEAR	**431**	75	32
CASH AND SHORT-TERM INVESTMENTS AT END OF YEAR	**$ 206**	$ 431	$ 75

Consolidated Balance Sheet

(stated in millions of Canadian dollars)

As at December 31,	1999	1998
ASSETS		
CURRENT ASSETS		
Cash and short-term investments (Note 10)	**$ 206**	$ 431
Accounts receivable	**941**	683
Inventories (Note 11)	**501**	455
Prepaid expenses	**25**	15
	1 673	1 584
PROPERTY, PLANT AND EQUIPMENT, NET (Note 12)	**6 719**	6 433
DEFERRED CHARGES AND OTHER ASSETS (Note 13)	**269**	381
	$ 8 661	$ 8 398
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	**$ 1 307**	$ 1 063
Income taxes payable	**72**	95
Current portion of long-term debt	**4**	3
	1 383	1 161
LONG-TERM DEBT (Note 14)	**1 707**	1 826
DEFERRED CREDITS AND OTHER LIABILITIES (Note 15)	**355**	362
DEFERRED INCOME TAXES	**1 133**	1 113
COMMITMENTS AND CONTINGENT LIABILITIES (Note 21)		
SHAREHOLDERS' EQUITY (Note 16)	**4 083**	3 936
	$ 8 661	$ 8 398

Approved on behalf of the Board

R.A. Brenneman

Ronald A. Brenneman
Director

Claude Fontaine

Claude Fontaine
Director

Notes to Consolidated Financial Statements

(tabular amounts stated in millions of Canadian dollars)

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation The consolidated financial statements include the accounts of Petro-Canada and of all subsidiary companies ("the Company") and comply in all material respects with Canadian generally accepted accounting principles.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingencies at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

(b) Cash and Short-Term Investments Cash and short-term investments comprise cash in the bank, less outstanding cheques, and deposits with a maturity of less than one year.

(c) Inventories Inventories are stated at the lower of cost and net realizable value. Cost of crude oil and products is determined primarily on a "last-in, first-out" basis.

(d) Investments Investments in companies over which the Company has significant influence are accounted for on the equity method. Other long-term investments are accounted for on the cost method.

(e) Property, Plant and Equipment Investments in exploration and development activities are accounted for on the successful efforts method. Under this method the acquisition cost of unproved acreage is capitalized. Costs of exploratory wells are initially capitalized pending determination of proved reserves and costs of wells which are assigned proved reserves remain capitalized while costs of unsuccessful wells are charged to earnings. All other exploration costs are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

Substantially all of the Company's exploration and development activities are conducted jointly with others. Only the Company's proportionate interest in such activities is reflected in the financial statements.

The interest cost of debt attributable to the construction of major new facilities is capitalized during the construction period.

(f) Depreciation, Depletion and Amortization Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the unit of production method.

Depreciation of other plant and equipment is provided on either the unit of production method or the straight line method, based on the estimated service lives of the related assets, as appropriate.

The carrying amounts of unproved properties are evaluated periodically for impairment with any such impairment being charged to earnings.

(g) Future Removal and Site Restoration Costs Estimated future removal and site restoration costs which are probable and can be reasonably determined are provided for on either the unit of production method or the straight line method, based on the estimated service lives of the related assets, as appropriate.

(h) Translation of Foreign Currency Monetary assets and liabilities are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. Other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expense items are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings, except for unrealized exchange gains or losses arising on translation of long-term debt, which are deferred and amortized over the remaining term of the debt.

Foreign operations are integrated with the Company's other activities and are translated in the manner described above.

(i) Hedging Activity The Company uses derivative instruments to reduce its exposure to foreign exchange, interest rate and commodity price fluctuations. Gains and losses on these contracts, all of which constitute effective hedges, are deferred and recognized as a component of the related transaction.

(j) Post Retirement Benefits In addition to its pension plans the Company provides other post retirement benefits, including health, dental and life insurance, to its qualifying retirees. The actuarially determined cost of these benefits is accrued over the estimated service lives of employees.

(k) Stock Option Plan The Company maintains a stock option plan for directors, officers and certain employees. Consideration paid on exercise of stock options is credited to common and variable voting shares and no compensation expense is recognized when stock options or stock are issued.

Notes to Consolidated Financial Statements (tabular amounts stated in millions of Canadian dollars)

Note 2 SEGMENTED INFORMATION

The Company operates in two business segments:

Upstream, comprising: exploration, development, production, transportation and marketing activities for crude oil, natural gas, propane, field liquids, sulphur and oil sands; and extraction of liquids from natural gas.

Downstream, comprising: purchase and sale of crude oil; refining crude oil into oil products; and distribution and marketing of these and other purchased products.

	Upstream			Downstream		
	1999	1998	1997	**1999**	1998	1997
Revenue						
Sales to customers and other revenues	**$ 1 174**	$ 944	$ 1 131	**$ 4 975**	$ 4 057	$ 4 971
Inter-segment sales	**516**	492	698	**14**	11	9
Segment Revenue	**$ 1 690**	$ 1 436	$ 1 829	**$ 4 989**	$ 4 068	$ 4 980
Earnings						
Earnings (loss) before the following:	**$ 930**	$ 618	$ 854	**$ 335**	$ 444	$ 505
Depreciation, depletion and amortization	**399**	385	347	**158**	137	128
Exploration expense	**78**	95	75	**—**	—	—
Interest	**—**	—	—	**—**	—	—
Provision for (recovery of) income taxes						
— current	**52**	151	(67)	**192**	73	113
— deferred	**152**	(72)	313	**(121)**	65	45
Reorganization costs (Note 4)	**—**	—	—	**—**	—	—
Net Earnings (Loss)	**$ 249**	$ 59	$ 186	**$ 106**	$ 169	$ 219
Capital and Exploration Expenditures						
Property, plant and equipment and exploration expenditures	**$ 793**	$ 818	$ 805	**$ 220**	$ 276	$ 215
Deferred charges and other assets	**(3)**	15	9	**(5)**	(7)	10
	$ 790	$ 833	$ 814	**$ 215**	$ 269	$ 225
Total Assets	**$ 5 052**	$ 4 635	$ 4 765	**$ 3 301**	$ 3 070	$ 3 085
Capital Employed	**$ 3 525**	$ 3 306	$ 3 270	**$ 2 084**	$ 1 958	$ 2 003

Financial information by business segment is presented in the following table as though each segment were a separate business entity. Inter-segment transfers of products, which are accounted for at market value, are eliminated on consolidation. Shared Services includes investment income, interest expense and general corporate revenue and expense. Shared Services assets are principally cash and short-term investments and other general corporate assets.

Shared Services			Consolidated		
1999	1998	1997	**1999**	1998	1997
$ (2)	$ 15	$ (6)	**$ 6 147**	$ 5 016	$ 6 096
—	—	—			
$ (2)	$ 15	$ (6)			
$ (66)	$ (32)	$ (60)	**$ 1 199**	$ 1 030	$ 1 299
1	8	7	**558**	530	482
—	—	—	**78**	95	75
141	122	106	**141**	122	106
(97)	(40)	(87)	**147**	184	(41)
11	(31)	13	**42**	(38)	371
—	—	—	**—**	42	—
$ (122)	$ (91)	$ (99)	**$ 233**	$ 95	$ 306
$ 8	$ 22	$ 29	**$ 1 021**	$ 1 116	$ 1 049
13	9	(4)	**5**	17	15
$ 21	$ 31	$ 25	**$ 1 026**	$ 1 133	$ 1 064
$ 308	$ 693	$ 488	**$ 8 661**	$ 8 398	$ 8 338
$ 98	$ 289	$ 245	**$ 5 707**	$ 5 553	$ 5 518

Notes to Consolidated Financial Statements (tabular amounts stated in millions of Canadian dollars)

Note 3 TAXES AND CROWN ROYALTIES

In addition to the provision for income taxes and other taxes included in the consolidated statement of earnings, the following items have been collected or produced on behalf of governments and have been paid or are payable by the Company:

	1999	1998	1997
Provincial fuel and sales taxes	$ 1 464	$ 1 418	$ 1 356
Federal excise taxes	839	819	820
Goods and Services Tax collected	632	602	680
Crown royalties, paid and paid in kind	171	125	217
	$ 3 106	$ 2 964	$ 3 073

Note 4 GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses in 1998 included a provision of $64 million before income tax for the reorganization of the Company's downstream administration. The provision decreased 1998 net earnings by $42 million.

Note 5 INCOME TAXES

The computation of the provision for income taxes, which requires adjustment to earnings before income taxes for non-taxable and non-deductible items, is as follows:

	1999	1998	1997
Earnings before income taxes	$ 422	$ 219	$ 636
Add (deduct):			
Non-deductible royalties and other payments to provincial governments, net	170	130	198
Resource allowance	(213)	(123)	(188)
Non-deductible depreciation, depletion and amortization and disposals	70	125	145
Equity in earnings of affiliates	(11)	(10)	(7)
Other	3	(13)	7
Earnings as adjusted before income taxes	$ 441	$ 328	$ 791
Canadian Federal income tax rate	38.0%	38.0%	38.0%
Canadian Federal income tax on earnings as adjusted	$ 168	$ 125	$ 301
Large Corporations Tax	14	14	14
Provincial and other income taxes, net of federal abatement	28	14	34
Rebates and other	(21)	(29)	(19)
Provision for income taxes	$ 189	$ 124	$ 330
Effective income tax rate on earnings before income taxes	44.8%	56.6%	51.9%

Complex income tax issues which involve interpretations of continually changing regulations are encountered in computing the provision for income taxes. Management believes that adequate provision has been made for all such outstanding issues.

Note 6 EARNINGS PER SHARE

The basic earnings per share, based on the weighted average number of common and variable voting shares outstanding in 1999 of 271.5 million (1998 — 271.2 million; 1997 — 270.9 million), for the year ended December 31, 1999 was $0.86 (1998 — $0.35; 1997 — $1.13). Fully diluted earnings per share, calculated on the assumption that all outstanding stock options were exercised, do not differ from the basic earnings per share.

Note 7 ITEMS NOT AFFECTING CASH FLOW

	1999	1998	1997
Depreciation, depletion and amortization	**$ 558**	$ 530	$ 482
Deferred income taxes	**42**	(42)	371
Provision for future removal and site restoration costs	**29**	28	30
Amortization of unrealized foreign exchange losses	**21**	24	16
(Gain) loss on sale of assets	**(3)**	3	(32)
Reclassification of current income taxes to proceeds from sales of assets (Note 9)	**—**	87	—
Other	**6**	10	15
	$ 653	$ 640	$ 882

Note 8 (INCREASE) DECREASE IN OPERATING WORKING CAPITAL AND OTHER

	1999	1998	1997
Accounts receivable	**$ (258)**	$ 221	$ 39
Income taxes recoverable	**—**	68	(68)
Inventories	**(46)**	55	(38)
Prepaid expenses	**(10)**	5	8
Accounts payable and accrued liabilities	**244**	(126)	(7)
Income taxes payable	**(23)**	95	(58)
Current portion of long-term liabilities and other	**(62)**	(56)	(43)
Sale of ICG Propane Inc.	**—**	(24)	—
	$ (155)	$ 238	$ (167)

Operating working capital is comprised of working capital other than cash and short-term investments and current portion of long-term debt.

Notes to Consolidated Financial Statements (tabular amounts stated in millions of Canadian dollars)

Note 9 PROCEEDS FROM SALES OF ASSETS

Proceeds from sales of assets in 1999 and 1997 relate to the sale of non-core oil and gas properties and other assets. Proceeds in 1998 include the sale of the Company's investment in Petro-Canada Centre, the sale of the Company's wholly-owned subsidiary, ICG Propane Inc., and the sale of non-core oil and gas properties and other assets. Current income taxes of $87 million relating to 1998 sales have been deducted from proceeds from sales of assets.

Note 10 CASH AND SHORT-TERM INVESTMENTS

The Company's short-term investments are considered to be cash equivalents and are recorded at cost, which approximates market value.

	1999	1998
Cash	**$ 316**	$ 45
Less: outstanding cheques	**(116)**	(65)
	200	(20)
Short-term investments	**6**	451
	$ 206	$ 431

Cash payments for interest and income taxes were as follows:

	1999	1998	1997
Interest expense	**$ 152**	$ 149	$ 140
Income taxes	**216**	64	100

Note 11 INVENTORIES

	1999	1998
Crude oil, refined products and merchandise	**$ 414**	$ 382
Materials and supplies	**87**	73
	$ 501	$ 455

Note 12 PROPERTY, PLANT AND EQUIPMENT

	1999			1998			Capital Expenditures	
	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Cost	Accumulated Depreciation, Depletion and Amortization	Net	**1999**	1998
Upstream								
Oil and gas								
Canada non-frontier	**$ 3 908**	**$ 1 898**	**$ 2 010**	$ 3 908	$ 1 869	$ 2 039	**$ 248**	$ 337
Hibernia	**1 067**	**113**	**954**	1 025	44	981	**42**	60
Terra Nova	**490**	**—**	**490**	248	—	248	**241**	165
Other frontier	**42**	**—**	**42**	19	—	19	**28**	9
Asset under capital lease	**92**	**7**	**85**	92	3	89	**—**	—
Foreign	**384**	**94**	**290**	349	60	289	**33**	55
Oil sands								
Syncrude	**781**	**273**	**508**	691	253	438	**90**	58
Other	**253**	**241**	**12**	233	228	5	**17**	12
Natural gas liquids	**298**	**201**	**97**	292	194	98	**6**	20
Other	**31**	**18**	**13**	48	36	12	**10**	7
	7 346	**2 845**	**4 501**	6 905	2 687	4 218	**715**	723
Downstream								
Refining	**2 737**	**1 499**	**1 238**	2 697	1 524	1 173	**129**	138
Marketing and other	**1 556**	**634**	**922**	1 566	593	973	**91**	138
	4 293	**2 133**	**2 160**	4 263	2 117	2 146	**220**	276
Other property, plant and equipment	**415**	**357**	**58**	407	338	69	**8**	22
	$ 12 054	**$ 5 335**	**$ 6 719**	$ 11 575	$ 5 142	$ 6 433	**$ 943**	$ 1 021

Interest capitalized during 1999 amounted to $11 million (1998 — $32 million; 1997 — $35 million).

Capital expenditures and exploration expenses charged to earnings are classified as investing activities in the consolidated statement of cash flows.

Costs relating to the Terra Nova and Other frontier are not currently being amortized.

The Company is party to an agreement for the time charter and operation of a vessel for the transportation of crude oil produced from Hibernia. This time charter is for an initial term of 10 years ending in 2007, and is extendible at the Company's option for an additional 15 years. The time charter has been accounted for as a capital lease (Note 14).

Note 13 DEFERRED CHARGES AND OTHER ASSETS

	1999	1998
Translation adjustment on long-term debt	**$ 87**	$ 212
Deferred pension funding	**55**	58
Investments	**77**	51
Deferred financing costs	**19**	20
Other	**31**	40
	$ 269	$ 381

Notes to Consolidated Financial Statements (tabular amounts stated in millions of Canadian dollars)

Note 14 LONG-TERM DEBT

	Maturity	1999	1998
Debentures and notes			
8.60% unsecured notes (U.S. $300 million)	2001	$ 433	$ 459
9.25% unsecured debentures (U.S. $300 million)	2021	433	459
7.875% unsecured debentures (U.S. $275 million)	2026	397	421
7.00% unsecured debentures (U.S. $250 million)	2028	361	383
Other		—	12
Capital lease (Note 12)[1]	2022	87	95
		1 711	1 829
Current portion		4	3
		$ 1 707	$ 1 826

1 The implicit rate of interest in the capital lease is 11.90%. The aggregate repayment will be $87 million (U.S. $60 million), including $4 million (U.S. $3 million) to $6 million (U.S. $4 million) in each of the next five years.

The minimum repayment of long-term debt, other than the capital lease, in the next five years will be a payment of $433 million (U.S. $300 million) in 2001.

Interest on long-term debt was $137 million in 1999 (1998 — $120 million; 1997 — $103 million).

Note 15 DEFERRED CREDITS AND OTHER LIABILITIES

	1999	1998
Future removal and site restoration costs	$ 177	$ 181
Post retirement benefits	118	115
Long-term liabilities	60	66
	$ 355	$ 362

Note 16 SHAREHOLDERS' EQUITY

	1999	1998
Common and variable voting shares	$ 1 223	$ 1 217
Contributed surplus	2 572	2 572
Retained earnings	288	147
	$ 4 083	$ 3 936

The authorized share capital of the Company is comprised of an unlimited number of:

(a) Preferred shares issuable in series designated as Senior Preferred Shares
(b) Preferred shares issuable in series designated as Junior Preferred Shares
(c) Common and variable voting shares

Note 16 SHAREHOLDERS' EQUITY (continued)

The common share capital is comprised of two classes of common equity: common shares which may be held only by residents of Canada and variable voting shares which may be held only by non-residents of Canada. The common shares and the variable voting shares differ only in their voting entitlements. The common shares carry one vote per share. The variable voting shares carry between one vote per share and 1/3 of one vote per share, depending on the number of variable voting shares outstanding compared to the number of voting shares outstanding. If the number of variable voting shares exceeds 25% of the public float of voting shares, the vote per variable voting share decreases so that the variable voting shares as a class do not carry more than 25% of the aggregate outstanding votes attached to all voting shares in the public float.

Changes in common and variable voting shares were as follows:

	1999 Shares	1999 Amount	1998 Shares	1998 Amount
Balance at beginning of year	**271 339 702**	**$ 1 217**	271 007 532	$ 1 211
Issued for cash under employee stock option and share purchase plans	**433 548**	**6**	332 170	6
Balance at end of year	**271 773 250**	**$ 1 223**	271 339 702	$ 1 217

Stock Option Plan

The Company maintains a stock option plan and may grant options to directors, officers and certain employees for up to 12 million common and variable voting shares. The stock options have a maximum term of 10 years, vest over periods of up to five years and are exercisable at the market prices for the shares on the dates that the options were granted.

Changes in the stock options were as follows:

	1999 Shares	1999 Weighted-Average Exercise Price (dollars)	1998 Shares	1998 Weighted-Average Exercise Price (dollars)
Balance at beginning of year	**5 359 451**	**$ 19**	4 057 342	$ 16
Granted	**1 882 500**	**17**	1 559 850	25
Exercised	**(432 875)**	**13**	(194 996)	12
Cancelled	**(108 065)**	**19**	(62 745)	22
Balance at end of year	**6 701 011**	**18**	5 359 451	19

The following stock options were outstanding as at December 31, 1999:

Option Outstanding				Options Exercisable	
Number	Range of Exercise Prices (dollars)	Weighted-Average Life (years)	Weighted-Average Exercise Price (dollars)	Number	Weighted-Average Exercise Price (dollars)
918 516	$ 8 to 13	2.7	$ 11	885 752	$ 10
2 980 645	14 to 18	7.4	16	1 056 069	16
2 801 850	20 to 26	7.7	23	980 669	23
6 701 011	8 to 26	7.2	18	2 922 490	16

Notes to Consolidated Financial Statements (tabular amounts stated in millions of Canadian dollars)

Note 17 PENSION PLANS

The Company maintains pension plans with defined benefit and defined contribution provisions. The defined benefit provisions are generally based upon years of service and average salary during the final years of employment. Certain defined benefit options require employee contributions and the balance of the funding for the registered plans is provided by the Company, based upon the advice of an independent actuary. Under the defined contribution provision, the Company's annual contribution is 5% of each participating employee's pensionable earnings. Substantially all of the pension assets are held in equity, fixed income and other marketable securities.

Pension Expense

	1999	1998	1997
Current service cost	**$ 24**	$ 25	$ 23
Interest cost	**67**	72	67
Actual return on plan assets	**(90)**	(123)	(117)
Net amortization and deferral	**3**	34	38
	$ 4	$ 8	$ 11
Pension Funding	**$ 6**	$ 6	$ 9

Financial Status of Defined Benefit Pension Plans

	1999	1998
Actuarial value of assets	**$ 1 025**	$ 963
Pension obligation	**875**	837
Net pension asset	**$ 150**	$ 126

The net pension asset is amortized to earnings over the expected average remaining service life of the employees covered by the defined benefit provisions of the plans, which is currently 9 years.

As at December 31, 1999 $863 million (1998 — $824 million) of the pension obligation was vested.

Defined Benefit Plan Assumptions

	1999	1998	1997
Discount rate	**8.0%**	9.0%	9.0%
Long-term rate of return on plan assets	**8.0%**	9.0%	9.0%
Rate of compensation increase, excluding merit increases	**2.0%** [1]	3.0%	3.0%

1 2.5% in 2000 and 3.0% per year thereafter.

Note 18 RELATED PARTY TRANSACTIONS

Transactions with the Government of Canada (which holds 18% of the Company's issued shares at December 31, 1999), its agencies and other related parties, are in the normal course of business and are therefore on the same terms as those accorded to non-related parties.

As at December 31, 1999 officers and employees owed the Company $1 million (1998 — $2 million) in relation to stock purchase plans.

Note 19 FAIR VALUE OF FINANCIAL INSTRUMENTS

As at December 31, 1999 the fair value and the related method of determination along with the carrying value of the Company's financial instruments were as follows:

Cash and Short-Term Investments

The fair value of cash and short-term investments approximates the carrying amount of these instruments due to their short maturity.

Long-Term Debt

The fair value of long-term debt is based on publicly quoted market values.

Derivative Instruments

The fair value of derivative instruments is based on quotes provided by brokers. The fair value of these financial instruments represents an approximation of amounts that would be received or paid to counterparties to settle these instruments prior to maturity. The Company plans to hold all derivative instruments, outstanding as at December 31, 1999, to maturity.

	Carrying Amount	Fair Value
Cash and short-term investments	$ 206	$ 206
Long-term debt[1]	(1 711)	(1 738)
Derivative instruments	—	6

1 Excludes translation adjustment of $87 million (Note 13).

Note 20 DERIVATIVE INSTRUMENTS

The Company is exposed to market risks resulting from fluctuations in foreign exchange, interest rates and commodity prices in the course of its normal business operations. The Company actively monitors its exposure to market fluctuations and employs the use of derivative instruments to manage these risks, as it considers appropriate. These derivative instruments are entered into solely for hedging purposes.

Crude Oil and Products

The upstream business segment has sold forward crude in order to mitigate exposure to price volatility. The downstream business segment uses forward contracts and options to reduce exposure to margin fluctuations, including margins on fixed price product sales, and short-term price fluctuations on the purchase of foreign and domestic crude oil and refined products.

Natural Gas

The Company has entered into fixed price and basis swap contracts to balance term, location and price exposure in order to reduce the overall effect of natural gas price volatility.

Notes to Consolidated Financial Statements (tabular amounts stated in millions of Canadian dollars)

Note 20 DERIVATIVE INSTRUMENTS (continued)

The Company's outstanding contracts for derivative instruments and related unrealized gains (losses) were as follows:

December 31, 1999	Quantity or Notional Principal	Average Price[1]	Unrealized Gains (Losses)	Maturity
Crude Oil and Products (millions of barrels)				
Crude oil — upstream	**2.0**	**$ 32.55**	**$ (6)**	**2000**
— downstream	**3.3**	**28.44**	**10**	**2000/2003**
Products — downstream	**8.2**	**32.99**	**—**	**2000/2001**
			4	
Natural Gas (billions of cubic feet)				
Natural gas — bought	**1.0**	**3.17**[2]	**—**	**2000**
Natural gas — sold	**5.1**	**3.11**[2]	**1**	**2000**
Natural gas — swaps	**1.5**	**—**[4]	**1**	**2000**
			2	
			$ 6	

December 31, 1998	Quantity or Notional Principal	Average Price[1]	Unrealized Gains (Losses)	Maturity
Crude Oil and Products (millions of barrels)				
Crude oil	8.5	$ 20.46	$ (9)	1999/2000
Products	1.8	19.29	—	1999
			(9)	
Natural Gas (billions of cubic feet)				
Natural gas — bought	2.3	2.68[2]	—	1999
Natural gas — sold	20.6	2.36[2]	(1)	1999
Natural gas — swaps	37.9	—[4]	—	1999/2000
			(1)	
Currency (U.S. dollars)				
Collars	$ 25	1.4000-1.4475[3]	(2)	1999
			$ (12)	

1 Canadian dollars per barrel, per thousand cubic feet or per U.S. dollar, as applicable.
2 Represents the volume weighted average prices at plant gate.
3 Represents the weighted-average Canadian call and put strike prices, respectively.
4 Basis swaps are priced at a differential between two market points rather than an absolute price.

Derivative instruments involve a degree of credit risk which the Company controls through the establishment of credit policies and limits and the selection of financially sound counterparties. Market risk relating to changes in value or settlement cost of the Company's derivative instruments is essentially offset by gains or losses on the hedged positions.

Note 21 COMMITMENTS AND CONTINGENT LIABILITIES

(a) The Company is a participant in the project to develop the Terra Nova offshore oil field. Costs to production start-up are estimated at $2.2 billion; the Company's 29% share is expected to be approximately $627 million (before investment tax credits), of which $466 million had been expended to December 31, 1999. The Company's share of development costs subsequent to start-up is estimated at $230 million, which is expected to be financed by cash flow from the Project.

(b) The Company has leased property and equipment under various long-term operating leases for periods up to 2013. The minimum annual rentals for non-cancellable operating leases are estimated at $83 million in 2000, $76 million in 2001, $63 million in 2002, $55 million in 2003, $49 million in 2004 and $42 million per year thereafter until 2013.

(c) The Company is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company.

Note 22 COMPARATIVE FIGURES

Reclassifications are made to the prior years' comparative figures to conform with the current year's presentation.

Note 23 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP") IN THE UNITED STATES

The Company's consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada, which differ in some respects from those applicable in the United States. The following are the significant differences in accounting principles as they pertain to the accompanying consolidated financial statements:

(a) The Company follows the deferral method of accounting for income taxes. Under United States GAAP the use of the liability method would be required.

(b) The Company has deferred unrealized gains and losses on translation of long-term debt payable in foreign currencies for amortization over the remaining term of the debt. Under United States GAAP gains or losses on the translation of long-term debt payable in foreign currencies would be credited or charged to earnings with no deferral.

(c) United States GAAP requires that interest be capitalized as part of the cost of certain assets while they are being prepared for their intended use. The Company capitalizes interest attributable to the construction of major new facilities and does not capitalize interest on all assets which would require interest capitalization under United States GAAP.

(d) In prior years the Company transferred amounts from contributed surplus to the accumulated deficit. Under United States GAAP these transfers would not have occurred.

(e) United States GAAP utilizes the concept of comprehensive income which includes items not included in net earnings. The Company's net earnings under United States GAAP is the same as its comprehensive income.

Notes to Consolidated Financial Statements (tabular amounts stated in millions of Canadian dollars)

Note 23 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP") IN THE UNITED STATES (continued)

The application of United States GAAP would have the following effects on earnings as reported:

	1999	1998	1997
Net earnings as reported in the consolidated statement of earnings	**$ 233**	$ 95	$ 306
Adjustments, net of applicable income taxes			
Accounting for income taxes	**3**	(2)	(10)
Foreign currency translation	**85**	(46)	(26)
Capitalization of interest and related amortization	**11**	21	16
Other	**(1)**	1	(1)
Net earnings, as adjusted	**$ 331**	$ 69	$ 285
Earnings per share, as adjusted	**$ 1.22**	$ 0.25	$ 1.05

The application of United States GAAP would have the following effects on the consolidated balance sheets as reported:

	As Reported	Increase (Decrease)	United States GAAP
December 31, 1999			
Current assets	**$ 1 673**	**$ —**	**$ 1 673**
Property, plant and equipment, net	**6 719**	**561**	**7 280**
Deferred charges and other assets	**269**	**(95)**	**174**
Current liabilities	**1 383**	**—**	**1 383**
Long-term debt	**1 707**	**—**	**1 707**
Deferred income taxes	**1 133**	**411**	**1 544**
Contributed surplus	**2 572**	**1 122**	**3 694**
Retained earnings (deficit)	**288**	**(1 067)**	**(779)**
December 31, 1998			
Current assets	$ 1 584	$ (22)	$ 1 562
Property, plant and equipment, net	6 433	534	6 967
Deferred charges and other assets	381	(199)	182
Current liabilities	1 161	(16)	1 145
Long-term debt	1 826	(17)	1 809
Deferred income taxes	1 113	389	1 502
Contributed surplus	2 572	1 122	3 694
Retained earnings (deficit)	147	(1 165)	(1 018)

Supplemental Information

Net Proved Reserves of Crude Oil and Natural Gas Before Royalties

Proved reserves of crude oil and liquids were unchanged in 1999 at 476 million barrels as discoveries, extensions and revisions offset production and net dispositions. The major positive change was the booking of 25 million barrels at Hibernia. Other positive changes included discoveries, extensions and revisions of 10 million barrels in Western Canada and four million barrels in International. Offsetting the positive changes were production of 34 million barrels and sales of five million barrels of Western Canada properties.

Proved reserves of natural gas decreased by 22 billion cubic feet to 2 481 billion cubic feet. Major positive changes included the addition of 279 billion cubic feet from discoveries, extensions and revisions and purchases of nine billion cubic feet from several Western Canada transactions. Offsetting these positive changes were sales of 47 billion cubic feet of minor Western Canada properties and production of 263 billion cubic feet.

Based on the better-than-expected quality of the Hibernia reservoir, Petro-Canada now estimates its share of ultimate reserves at Hibernia to be 146 million barrels. No proved reserves have yet been booked for Terra Nova or other Grand Banks discoveries, or for Algerian discoveries other than Tamadanet.

Net Proved Developed and Undeveloped Reserves Before Royalties [1,2]

	Crude Oil And Field Natural Gas Liquids (millions of barrels)					Natural Gas (billions of cubic feet)
	Western Canada	International [3,4]	Grand Banks [5]	Synthetic Crude Oil [6]	Total	Total
Beginning of year 1997	173	23	—	256	452	2 585
Revisions of previous estimates	2	(2)	—	7	7	51
Sale of reserves in place	(11)	—	—	—	(11)	(183)
Purchase of reserves in place	1	—	—	—	1	63
Discoveries, extensions and improved recovery	8	1	8	—	17	280
Production	(21)	(4)	—	(9)	(34)	(277)
End of year 1997	152	18	8	254	432	2 519
Revisions of previous estimates	9	(2)	—	(43)	(36)	57
Sale of reserves in place	(32)	—	—	—	(32)	(123)
Purchase of reserves in place	1	—	—	—	1	31
Discoveries, extensions and improved recovery	6	2	12	127	147	284
Production	(18)	(5)	(4)	(9)	(36)	(265)
End of year 1998	118	13	16	329	476	2 503
Revisions of previous estimates	5	—	—	—	5	(16)
Sale of reserves in place	(5)	—	—	—	(5)	(47)
Purchase of reserves in place	—	—	—	—	—	9
Discoveries, extensions and improved recovery	5	4	25	—	34	295
Production	(13)	(4)	(7)	(10)	(34)	(263)
End of year 1999	**110**	**13**	**34**	**319**	**476**	**2 481**

1 Net proved developed and undeveloped reserves before royalties are Petro-Canada's working interest in reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. No reserve quantities have been included to reflect royalty interests Petro-Canada has in various properties.

2 Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves that are expected to be recovered from existing wells or facilities. Proved undeveloped reserves are proved reserves which are not recoverable from existing wells or facilities, but which are expected to be recovered through additional development drilling or through the upgrading of existing or additional new facilities.

3 International proved reserves comprise 10 million barrels of oil and nine billion cubic feet of natural gas in Norway, and three million barrels of oil in Algeria.

4 After deduction of a 20 per cent royalty, Petro-Canada receives crude oil to recover costs incurred on behalf of Petro-Canada and SONATRACH, the Algerian state oil company. The remaining production is shared between Petro-Canada and SONATRACH, varying with the level of production. The total share accruing to Petro-Canada cannot exceed 49.per cent of gross production volumes.

5 Proved reserves at Hibernia are based on primary recovery for drilled fault blocks and undrilled fault blocks which lie between drilled fault blocks and incremental recovery in fault blocks showing response to water or gas injection.

6 Proved reserves of synthetic crude oil are based on high geological certainty, with drilling hole spacing less than 700 metres and application of existing or piloted technology. Appropriate co-owner and regulatory approvals are in place.

Net Probable Reserves of Crude Oil and Natural Gas Before Royalties

Probable reserves of crude oil and liquids decreased by 16 million barrels in 1999 to 416 million barrels. The major positive change was the booking of a 22 million barrel revision at Hibernia. Offsetting the positive change were reclassifications of 25 million barrels at Hibernia and four million barrels in International as proved and International revisions of nine million barrels.

Probable reserves of natural gas increased by 13 billion cubic feet to 1 157 billion cubic feet. Positive changes included domestic discoveries, extensions and revisions of 24 billion cubic feet and domestic purchases of three billion cubic feet. Partially offsetting these changes were domestic sales of three billion cubic feet of minor Western Canada properties and International discoveries, extensions and revisions of negative 11 billion cubic feet.

Net Probable Reserves Before Royalties [1,2]	Crude Oil And Field Natural Gas Liquids (millions of barrels)					Natural Gas (billions of cubic feet)
	Western Canada	International [3,4]	Grand Banks	Synthetic [5] Crude Oil	Total	Total
End of year 1998	39	50	210	133	432	1 144
Revisions of previous estimates	1	(9)	22	—	14	56
Sale of reserves in place	—	—	—	—	—	(3)
Purchase of reserves in place	—	—	—	—	—	3
Discoveries, extensions and improved recovery	(1)	(4)	(25)	—	(30)	(43)
End of year 1999	**39**	**37**	**207**	**133**	**416**	**1 157**

1 Net probable reserves before royalties are Petro-Canada's working interest in reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. No reserve quantities have been included to reflect royalty interests Petro-Canada has in various properties.

2 Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves. Probable reserves are less certain than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to be recovered than not.

3 International probable reserves comprise 25 million barrels of oil and natural gas liquids and 194 billion cubic feet of natural gas in Algeria, and 12 million barrels of oil and natural gas liquids and 27 billion cubic feet of natural gas in Norway.

4 After deduction of a 20 per cent royalty, Petro-Canada receives crude oil to recover costs incurred on behalf of Petro-Canada and SONATRACH, the Algerian state oil company. The remaining production is shared between Petro-Canada and SONATRACH, varying with the level of production. The total share accruing to Petro-Canada cannot exceed 49 per cent of gross production volumes.

5 Proved reserves of synthetic crude oil are based on high geological certainty, with drilling hole spacing less than 700 metres and application of existing or piloted technology. Appropriate co-owner approvals are in place and regulatory approvals are being sought.

Crude Oil

Principal Reserve and Production Locations

Fields	Proved Reserves Before Royalties [1] at December 31, 1999 (millions of barrels)	Per Cent of Total Proved Oil Reserves	Average 1999 Daily Production Before Royalties [1] (thousands of barrels)	Per Cent of Total 1999 Daily Oil Production
Syncrude, Alberta	319.3	72	26.7	32
Hibernia, offshore Newfoundland	33.6	8	20.0	24
Pembina, Alberta [2]	17.1	4	2.3	3
Valhalla, Alberta [3]	14.5	3	7.2	9
Ferrier, Alberta	14.2	3	3.5	4
Boundary Lake, British Columbia [2]	10.9	2	1.8	2
Veslefrikk, offshore Norway	6.1	1	3.1	3
Willesden Green, Alberta	5.3	1	1.8	2
Njord, offshore Norway	3.9	1	4.6	6
Wapiti, Alberta [3]	3.4	1	0.9	1
Other [4]	15.1	4	11.7	14
Total	**443.4**	**100**	**83.6**	**100**

1 Does not include natural gas liquids.

2 Sale of these properties was announced in the first quarter of 2000.

3 Sale of these properties is expected in 2000.

4 Sale of the majority of these properties is expected in 2000.

Natural Gas

Principal Reserve and Production Locations

Fields	Proved Reserves Before Royalties[1] at December 31, 1999 (billions of cubic feet)	Per Cent of Total Proved Gas Reserves	Average 1999 Daily Production Before Royalties[1] (millions of cubic feet)	Per Cent of Total 1999 Daily Gas Production
Wildcat Hills, Alberta	502	20	74	10
Hanlan, Alberta	285	12	105	15
Jedney/Beg/Bubbles, British Columbia	230	9	42	6
Ricinus/Bearberry, Alberta	181	7	85	12
Fort St. John, British Columbia	125	5	29	4
Gilby, Alberta	112	5	37	5
Laprise Creek, British Columbia	109	4	25	4
Medicine Hat, Alberta	96	4	27	4
Brazeau, Alberta	93	4	46	6
Clarke Lake, British Columbia	89	4	40	6
Other	650	26	209	28
Total	**2 472**	**100**	**719**	**100**

1 Does not include natural gas liquids.

Oil and Gas Landholdings (Gross/Net)[1] (millions of acres)

	Developed[2]		Undeveloped[2]		Total	
	Gross	Net	Gross	Net	Gross	Net
Mainland Canada	2.6	1.3	3.0	2.0	5.6	3.3
Oil Sands	0.1	—	0.7	0.3	0.8	0.3
East Coast Offshore[3]	0.1	—	4.9	1.9	5.0	1.9
Other Frontier[4]	—	—	7.2	6.0	7.2	6.0
International[5]	—	—	3.4	3.4	3.4	3.4
Total	**2.8**	**1.3**	**19.2**	**13.6**	**22.0**	**14.9**

1 Gross acres includes the interests of others while net acres excludes the interest of others.
2 Developed lands are areas capable of production while undeveloped lands are areas with rights to explore.
3 East Coast offshore landholdings includes parcels acquired at the 1999 Newfoundland and Nova Scotia land sales, for which licences were issued in the first quarter of 2000. These licences cover 1.6 million gross acres, 0.8 million net to Petro-Canada.
4 Exploration is not currently permitted in the Eastern Arctic or off the West Coast of Canada.
5 International landholdings are in Algeria, Norway and Tunisia.

Refining by Locations (thousands of cubic metres)

	Daily Rated Capacity as at December 31	Average Volumes of Crude Oil Processed per Calendar Day			
	1999	**1999**	1998	1997	1996
Edmonton, Alberta	**19.1**	**19.7**	17.2	19.0	18.5
Montreal, Quebec	**16.7**	**16.4**	15.8	14.3	13.9
Oakville, Ontario	**13.2**	**12.8**	13.6	13.4	12.6
Total	**49.0**	**48.9**	46.6	46.7	45.0

Five-Year Financial and Operating Summary[1]

(stated in millions of dollars, unless otherwise indicated)

	1999	1998	1997	1996	1995
Consolidated					
Revenue	**$ 6 147**	$ 5 016	$ 6 096	$ 5 607	$ 4 820
Expenses	**5 725**	4 797	5 460	5 111	4 450
Provision for income taxes	**189**	124	330	249	174
Net earnings	**$ 233**	$ 95	$ 306	$ 247	$ 196
Cash flow	**964**	830	1 263	863	705
Total assets	**8 661**	8 398	8 338	7 769	6 488
Average capital employed	**5 630**	5 536	5 406	5 019	4 202
Operating return on capital employed (per cent) (in 1998 and 1995, before reorganization costs)	**5.6**	3.6	6.9	6.2	7.0
Return on capital employed (per cent)	**5.6**	3.0	6.8	6.2	5.9
Cash flow return on capital employed (per cent)	**18.6**	16.3	24.5	18.5	18.0
Debt	**1 711**	1 829	1 741	1 709	1 381
Debt to debt plus equity (per cent)	**29.5**	31.7	30.7	31.6	30.9
Debt to cash flow (times)	**1.8**	2.2	1.4	2.0	2.0
Expenditures on property, plant and equipment and exploration	**1 021**	1 116	1 049	959	853
Employees (number at year end)[2]	**4 417**	4 620	5 749	5 679	5 646
Shareholders' Data					
Weighted average number of common and variable voting shares outstanding (millions)	**271.5**	271.2	270.9	262.3	246.7
Shares outstanding at year end (millions)	**271.8**	271.3	271.0	270.7	246.7
Publicly held shares at year end (millions)	**222.4**	221.9	221.6	221.3	197.3
Share prices (dollars)[3]					
— at year end	**20.45**	16.25	26.00	19.35	15 3/4
— range during the year	**15.35-25.10**	14.55-26.95	18.90-29.85	15.63-20.60	10 7/8-15 7/8
Shares traded (millions)[4]	**203.7**	244.7	271.1	112.7	65.4
Book value per share (dollars)	**15.02**	14.51	14.47	13.64	12.53
Upstream Sector					
Earnings from operations	**$ 243**	$ 29	$ 188	$ 192	$ 153
Gains (losses) on asset sales	**6**	30	(2)	4	6
Net earnings	**$ 249**	$ 59	$ 186	$ 196	$ 159
Cash flow	**885**	516	900	655	477
Expenditures on property, plant and equipment and exploration	**793**	818	805	649	587

1 Certain reclassifications have been made to the figures previously reported to reflect subsequent changes in reporting presentation.
2 Numbers prior to 1998 include employees of ICG Propane Inc., a subsidiary that was sold in 1998.
3 Year-end prices are from the Toronto Stock Exchange; range during the year is from the Toronto and Montreal exchanges.
4 Total shares traded on all stock exchanges.
5 Average conventional crude oil, synthetic crude oil and field natural gas liquids price is after the impact of hedging activities.
6 Average gas price is before deduction of British Columbia gathering and processing charges.
7 Total daily refinery capacity has been restated as a result of a reassessment in the fourth quarter of 1998.
8 Average refinery utilization takes into account, where applicable, changes in refinery crude capacity that occurred during the year.

(stated in millions of dollars, unless otherwise indicated)

	1999	1998	1997	1996	1995
Upstream Sector (continued)					
Daily Production (net, before royalties)					
Crude oil and field liquids (thousands of barrels)	**95.3**	101.1	95.1	97.3	79.4
Natural gas (excluding injectants, millions of cubic feet)	**719**	722	760	712	546
Ethane and natural gas liquids production from straddle plants (thousands of barrels)	**29.7**	35.2	39.6	34.9	37.5
Average sales prices					
Crude oil and field liquids (per barrel)[5]	**24.58**	17.72	25.79	25.16	21.76
Natural gas (per thousand cubic feet)[6]	**2.59**	1.96	1.85	1.61	1.32
Proved Reserves (net, before royalties)					
Crude oil and field liquids (millions of barrels)	**476**	476	432	452	423
Natural gas (trillions of cubic feet)	**2.5**	2.5	2.5	2.6	2.1
Oil and Gas Landholdings (gross/net) (millions of acres)	**22.0/14.9**	19.2/13.3	17.3/12.0	16.7/11.7	14.3/10.4
Wells Drilled (gross/net)					
Oil	**51/13**	76/33	127/65	118/82	112/69
Natural gas	**164/95**	188/83	145/82	141/73	161/98
Dry	**26/8**	23/9	34/21	39/17	29/13
Total	**241/116**	287/125	306/168	298/172	302/180
Downstream Sector					
Earnings from operations	**$ 115**	$ 204	$ 225	$ 130	$ 160
Gains (losses) on asset sales	**(9)**	(35)	(6)	(3)	1
Net earnings	**$ 106**	$ 169	$ 219	$ 127	$ 161
Cash flow	**163**	420	415	243	305
Expenditures on property, plant and equipment	**220**	276	215	282	254
Petroleum product sales (thousands of cubic metres per day)	**51.2**	49.1	48.5	43.7	41.6
Retail outlets at year end	**1 658**	1 709	1 780	1 765	1 871
Refinery crude capacity at year end (thousands of cubic metres per day)[7]	**49.0**	49.0	45.4	45.4	45.4
Refinery crude capacity utilization (per cent)[8]	**100**	95	103	99	93

Quarterly Financial and Stock Trading Information

(unaudited, stated in millions of dollars unless otherwise indicated)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 1999	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 1998
Revenue								
Operating	**$ 1 086**	**$ 1 371**	**$ 1 673**	**$ 1 965**	$ 1 263	$ 1 200	$ 1 226	$ 1 262
Investment and other income	**19**	**19**	**14**	**—**	10	58	11	(14)
	1 105	**1 390**	**1 687**	**1 965**	1 273	1 258	1 237	1 248
Expenses								
Crude oil and product purchases	**520**	**715**	**967**	**1 234**	587	561	622	643
Producing, refining and marketing	**295**	**303**	**303**	**335**	339	329	313	328
General and administrative [1]	**57**	**60**	**51**	**53**	54	126	51	34
Exploration	**22**	**20**	**12**	**24**	32	9	27	27
Depreciation, depletion and amortization	**131**	**139**	**136**	**152**	130	136	129	135
Taxes other than income taxes	**15**	**13**	**15**	**12**	18	16	16	13
Interest	**33**	**35**	**36**	**37**	29	30	32	31
	1 073	**1 285**	**1 520**	**1 847**	1 189	1 207	1 190	1 211
Earnings Before Income Taxes	**32**	**105**	**167**	**118**	84	51	47	37
Provision for Income Taxes	**24**	**41**	**72**	**52**	48	26	32	18
Net Earnings	**$ 8**	**$ 64**	**$ 95**	**$ 66**	$ 36	$ 25	$ 15	$ 19
Cash Flow	**$ 165**	**$ 224**	**$ 260**	**$ 315**	$ 260	$ 173	$ 174	$ 223
Segmented Earnings								
Earnings from operations								
Upstream	**$ 7**	**$ 55**	**$ 83**	**$ 98**	$ 2	$ 5	$ (4)	$ 26
Downstream	**31**	**35**	**40**	**9**	63	55	52	34
Shared Services	**(31)**	**(28)**	**(30)**	**(33)**	(28)	(27)	(27)	(21)
Reorganization costs	**—**	**—**	**—**	**—**	—	(42)	—	—
	7	**62**	**93**	**74**	37	(9)	21	39
Gains (losses) on asset sales	**1**	**2**	**2**	**(8)**	(1)	34	(6)	(20)
Net earnings	**$ 8**	**$ 64**	**$ 95**	**$ 66**	$ 36	$ 25	$ 15	$ 19
Share Information (dollars per share)								
Earnings	**0.03**	**0.24**	**0.35**	**0.24**	0.13	0.09	0.06	0.07
Cash flow	**0.61**	**0.82**	**0.96**	**1.16**	0.96	0.64	0.64	0.82
Dividends per share	**0.08**	**0.08**	**0.08**	**0.10**	0.08	0.08	0.08	0.08
Share price [2]								
— High	**20.15**	**20.95**	**25.10**	**23.80**	26.95	26.65	24.70	21.40
— Low	**15.35**	**17.00**	**19.75**	**19.75**	21.75	22.20	14.55	15.80
— Close (end of period)	**17.65**	**20.10**	**22.25**	**20.45**	25.30	23.60	19.15	16.25
Shares traded (millions) [3]	**55.2**	**66.5**	**44.3**	**37.7**	65.1	62.7	57.4	59.5

1 General and administrative expenses for 1998 includes a provision of $64 million before income taxes for the reorganization of the Company's Downstream administration.
2 Share prices are for trading on the Toronto and Montreal stock exchanges.
3 Total shares traded on all stock exchanges.

Investor Information

Outstanding Shares

At December 31, 1999, Petro-Canada's public float was 222.4 million shares, comprised of 181.6 million common shares held by residents of Canada, and 40.8 million variable voting shares held by non-residents of Canada.

Transfer Agent and Registrar

In Canada, Petro-Canada's transfer agent and registrar is CIBC Mellon Trust Company. Share certificates may be transferred at CIBC Mellon's corporate offices in Halifax, Montreal, Toronto, Winnipeg, Regina, Calgary and Vancouver. Questions relating to share certificates, dividends and estate settlements should be directed to:

CIBC Mellon Trust Company
600 The Dome Tower
333 – 7th Avenue S.W.
Calgary, Alberta, Canada T2P 2Z1
Telephone toll-free: 1-800-387-0825
Fax: (416) 643-5501
E-mail: enquiries@cibcmellon.ca
Web site: www.cibcmellon.com

In the United States, Petro-Canada's transfer agent and registrar is:

ChaseMellon Shareholder Services, LLC
85 Challenger Road
Overpeck Center
Ridgefield Park, NJ 07660
Telephone toll-free: 1-800-387-0825
Fax: (416) 643-5501
E-mail: enquiries@cibcmellon.ca
Web site: www.cibcmellon.com

Stock Exchange Listings and Symbols

Toronto: PCA
New York: PCZ

Dividends

Petro-Canada's Board of Directors has adopted a policy of paying quarterly dividends of $0.10 ($0.40 per annum) per common and variable voting share. The Board reviews the dividend policy in light of the Company's financial position, its financing requirements for growth and other factors.

Dividends are normally paid on or about the first day of the months of January, April, July and October. The record dates are normally set approximately four weeks ahead of the dividend payment date. Dividends can be deposited directly to shareholders' bank accounts. If this service is desired, contact the transfer agent and registrar.

Information for Investors Outside of Canada

Dividends and interest payments made to residents in countries with which Canada has a bilateral tax treaty are generally subject to a Canadian non-resident withholding tax of 15 per cent. The majority of countries are in this category. For U.S. residents, these rates were reduced in 1996 to five per cent on certain dividends and 10 per cent on interest. There is no Canadian tax on gains from the sale of shares or debt instruments owned by non-residents not carrying on business in Canada. Estate taxes or succession duties are not levied by any level of government in Canada. (This summary is not intended as tax advice; shareholders may wish to consult a tax advisor with respect to particular circumstances.)

Duplicate Reports

While we try to avoid duplicate mailings of annual reports and other materials, shareholders with more than one unregistered account may receive duplicates. To eliminate duplicate mailings, contact the transfer agent and registrar.

Additional Publications

The following publications are available on our Web site or from Corporate Communications:

- Statistical Supplement to the Annual Report, containing 10-year financial information and more detailed operating data
- Annual Information Form, filed with Canadian securities regulators
- Form 40-F, filed with the U.S. Securities and Exchange Commission
- Quarterly Reports, published about four weeks after the end of the first, second and third quarters
- Fifth annual progress report in support of Canada's Climate Change Voluntary Challenge and Registry
- Annual Community Investment Report
- Petro-Canada's Code of Business Conduct

Investor Relations

Telephone: (403) 296-4040
Fax: (403) 296-3061
E-mail: investor@petro-canada.ca
Web site: www.petro-canada.ca/investor

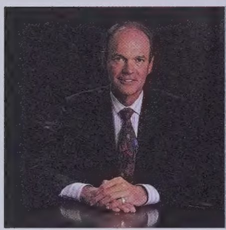
Media Enquiries

Corporate Communications
(403) 296-8482

General Enquiries

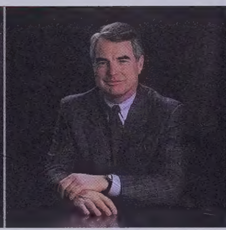
Petro-Canada
P.O. Box 2844
Calgary, Alberta, Canada T2P 3E3
Telephone: (403) 296-8000
Fax: (403) 296-3030
Web site: www.petro-canada.ca

Executive Leadership Team



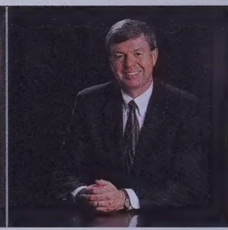
Ron Brenneman
President and Chief Executive Officer

Boris Jackman
Executive Vice-President (Downstream)



Bob McCaskill
Senior Vice-President

Norm McIntyre
Executive Vice-President (Upstream)



Harry Roberts
Senior Vice-President and Chief Financial Officer

BOARD OF DIRECTORS

Ronald A. Brenneman, a resident of Calgary, was appointed president and CEO and a director of Petro-Canada in January 2000. Mr. Brenneman has more than 30 years of industry experience in upstream, downstream and corporate roles, including senior executive positions with a major Canadian and international organization.

Angus A. Bruneau[1], a resident of St. John's, has been a director of Petro-Canada since 1996. Dr. Bruneau is chairman of Fortis Inc. and Air Nova. He is a director of Inco Limited, the SNC-Lavalin Group Inc., Canada Life Assurance Company, and North Atlantic Pipeline Partners L.P. He is a member of the Natural Sciences and Engineering Research Council and the Canadian Foundation for Innovation, and serves on the board of the Council for Canadian Unity.

Gail Cook-Bennett[1], a resident of Toronto, has been a director of Petro-Canada since 1991. Dr. Cook-Bennett is chairperson of the Canada Pension Plan Investment Board. She is a director of Cadillac Fairview Inc., Enbridge Consumers Gas Company, Groupe Transcontinental G.T.C. Ltee., Mackenzie Financial Corporation, and Manulife Financial.

John F. Cordeau[1], a resident of Calgary, has been a director of Petro-Canada since 1994. Mr. Cordeau is a partner and Litigation Department Head at Bennett Jones, a Calgary-based law firm. He is a director of Nav Canada.

Purdy Crawford, a resident of Toronto, has been a director of Petro-Canada since 1995. Mr. Crawford is the former chairman of Imasco Limited and chairman of AT&T Canada Corp. He is a director of Camco Inc., Canadian National Railway Company, Inco Limited, Maple Leaf Foods Inc., Nova Scotia Power Inc., and the Venator Group Inc.

Claude Fontaine[1], a resident of Montreal, has been a director of Petro-Canada since 1987. Mr. Fontaine is a senior partner and executive committee member of law firm Ogilvy Renault. He is a director of Domtar Inc., Optimum General Inc., the Montreal Heart Institute Research Fund and the Council for Canadian Unity.

Thomas E. Kierans, a resident of Toronto, has been a director of Petro-Canada since 1991, and served as chairman of the board from 1996 until January 2000. Mr. Kierans is chairman and CEO of the Canadian Institute for Advanced Research. He is chairman of Moore Corporation Limited, and the Toronto International Leadership Centre for Financial Sector Supervision. He is a director of Manufacturers Life Insurance Company, Fishery Products International Ltd., IPSCO Inc., Inmet Mining Corp., BCE Inc., CGI Group Inc. and National Bank Financial & Co. Inc. He is advisor to North Limited and Schroder Canada Limited.

Brian F. MacNeill, a resident of Calgary, has been a director of Petro-Canada since 1995. Mr. MacNeill is president and CEO of Enbridge Inc. He is chairman of Enbridge Consumers Gas Company. He is a director of the Alliance Pipeline, Toronto-Dominion Bank, Veritas DGC Inc., the C.D. Howe Institute, and the United Way of Calgary and Area. He is vice-chair of the advisory board of the 16th World Petroleum Congress. He is also a member of the Alberta and Ontario Institutes of Chartered Accountants and the Financial Executives Institute, and is a Fellow of the Canadian Institute of Chartered Accountants.

Guylaine Saucier[1], a resident of Montreal, has been a director of Petro-Canada since 1991. Ms. Saucier is chairperson of the Canadian Broadcasting Corporation and the Canadian Institute of Chartered Accountants. She is a director of the Bank of Montreal, Nortel Networks Corporation, AXA Assurances Inc., and Tembec Inc.

William W. Siebens, a resident of Calgary, has been a director of Petro-Canada since 1986. Mr. Siebens is president and chief executive officer of Candor Investments Ltd., and chairman of Freehold Royalty Trust. He is a director of the Canada Olympic Development Association and The Fraser Institute.

James M. Stanford, a resident of Calgary, has been a director of Petro-Canada since 1990, was president and CEO from 1993 to 2000, and was appointed chairman of the board in January 2000. Mr. Stanford is a director of Inco Limited, Fortis Inc., and the Canadian Wheat Board. He is a member of the Council for Canadian Unity, and serves on the Board of Governors of the University of Alberta.

1 Audit Committee member

THE ANNUAL MEETING OF SHAREHOLDERS WILL BE HELD AT 11:00 A.M. LOCAL TIME ON MONDAY, MAY 1, 2000 AT:

CRYSTAL BALLROOM, PALLISER HOTEL
133-9TH AVENUE S.W., CALGARY, ALBERTA

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25 YEARS

A quarter century — and running strong

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